Terasen Gas

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October 29, 2004

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

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

Dear Sir:

RE: Terasen Gas Inc.
2004 – 2007 Performance Based Rate Plan
2004 Annual Review - November 19, 2004
Terasen Gas Centre, Georgia Room - 8:30 a.m.
BCUC Order No. G-95-04

By Commission Order No. G-95-04, the British Columbia Utilities Commission ("the Commission") set November 19, 2004 as the date for the 2004 Terasen Gas Inc. Annual Review. This Annual Review will be the second under the Company's 2004 – 2007 Multi-Year Performance Based Rate settlement agreement ("the Settlement"). The Settlement was approved by Commission Order No. G-51-03 dated July 29, 2003. The Commission's approval of the Settlement followed a public hearing and Commission Decision on the Company's 2003 Revenue Requirement Application, an April 17, 2003 Application for a Multi-Year Performance Based Rate Plan for 2004-2008, information requests and responses and a negotiated settlement process in June and July 2003.

The terms of the Settlement require Terasen Gas to submit to the Commission and interested parties advance materials on the information to be presented at the Annual Review three weeks prior to the Annual Review. The details of Annual Review process are set out at Pages 17 to 22 of Appendix A of Commission Order No. G-51-03. The 2004 Annual Review is a process for the Company and stakeholders to ensure that the objectives of the Settlement are being achieved and to review the cost drivers and financial forecasts for the purposes of establishing the 2005 revenue requirements.

Enclosed are twenty (20) copies of the advance information for the 2004 Annual Review. This includes information on the cost drivers, and financial projections and forecasts necessary for setting delivery rates for 2005 in Section A of the binder, and, in Section B of the binder, various other reports and information identified in the Settlement and Commission Order No. G-51-03. Terasen Gas will present information at the Annual Review on the matters addressed in the advance materials.

The 2005 revenue requirement decrease identified in the enclosed materials is $1.0 million, equivalent to a 0.21% decrease in gross margin or a 0.07% decrease in total revenue at existing rates. Customer growth is the largest contributor to the revenue requirement decrease, accounting for about $4.7 million increase in revenues. Revenues from Southern Crossing Pipeline contributed an additional $3.1 million which, combined with the customer growth, helped to offset projected cost pressures. When the effects of the projected changes to the RSAM and Earnings Sharing Mechanism riders are factored in, residential customers can expect a decrease of 0.5% at the burnertip. A summary of the contributors to the decrease are summarized at Tab A-1, Page 4.

The revenue requirement information included is based on the allowed 2004 return on equity ("ROE") at 9.15%. Variances from this allowed ROE level arising from the Commission's generic ROE mechanism will lead to corresponding changes in the final 2005 revenue requirement applied for. Any rate changes related to the flow-through of gas cost changes will be dealt with in a separate application to the Commission.

We trust the enclosed is satisfactory. To assist in the planning of the review, it would be appreciated if you can contact Regulatory Affairs by email at regulatory.affairs@terasengas.com or by phone (604) 592-7664 to advise of your attendance on November 19, 2004.

Yours very truly,

TERASEN GAS INC.

Original signed by:

Scott Thomson

c. 2004 – 2007 PBR NSP Participants
2004 Annual Review Registered Participants

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2005 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

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TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2005 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-1 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
SUMMARY OF REVENUE REQUIREMENTS
FOR THE YEAR ENDING DECEMBER 31, 2005

By Order No. G-51-03 dated July 29, 2003, the Commission approved the Negotiated Settlement of the Terasen Gas Inc. (“Terasen Gas”) Multi-Year Performance Based Rate Plan for 2004 – 2007 (the “Settlement” or “PBR”).

Pursuant to the provisions of the Settlement Agreement, Terasen Gas has developed the projections and forecasts needed to establish the 2005 revenue requirement. The attached costs and revenues incorporate updated data for:

- 2004 projected year-end customers,
- 2004 projected formula-based capital expenditures trued up for customer additions and average total customer and resulting year-end plant balances and other rate base information,
- 2004 projected deferral account balances and amortization,
- 2004 projected formula-based utility O&M trued up for average total customer,
- Other projected 2004 cost-of-service items required under the terms of the Settlement for the setting of 2005 rates,
- 2005 forecast cost drivers, such as customer addition, average total customers and inflation,
- 2005 customer use rate forecasts,
- 2005 forecast volumes and revenues,
- 2005 formula-based utility O&M expenses including adjustments as per the terms of the Settlement for the change in pension and insurance forecast costs,
- 2005 formula-based base capital expenditures and resulting plant balances, accumulated depreciation and contributions-in-aid-of-construction,
- 2005 forecast property taxes,
- 2005 forecast working capital, deferred account balances and amortization, and

- 2005 forecast long-term debt and long-term and unfunded debt costs to be included in 2005 rates.

A summary of the 2005 revenue requirement decrease determined pursuant to the terms of the Settlement Agreement and the Revised Target is shown on the following financial summary pages:

Page 5 Summary of Rate Decrease Required

Page 6 Utility Rate Base

Page 7 Utility Income and Earned Return

Page 8 Income Taxes / Revenue Surplus

Page 9 Return on Capital

The 2005 test year costs and revenues are explained under the following section of this Annual Review material:

- Cost Drivers - see Section A, Tab 2,
- gas plant in service, plant additions and other rate base components - see Section A, Tab 3,
- volumes and revenues - see Section A, Tab 4 ,
- operating and maintenance costs - see Section A, Tab 5,
- taxes and other expenses - see Section A, Tab 6,
- financing costs - See Section A, Tab 7, and
- 2004 projected results - see Section A, Tab 8.

The results of incorporating the forecast and formula-based costs and revenues in the 2005 test year show that the revenue requirement decrease is $1.0 million, equivalent to a 0.21% decrease in gross margin, or a 0.07% decrease in total revenue at existing rates.

The volume and revenue forecast is the largest contributor to the $1.0 million revenue requirement decrease, being about a $4.7 million increase in revenues. The increase in customer growth is the major factor and this is discussed in more detail in Section A, Tab 4. Revenues from SCP contributed an additional $3.1 million. Mitigating the additional revenues are increases to cost of service items such as higher Operating and Maintenance expenses and depreciation and higher rate base. A summary of the components of the revenue requirement decrease is at Page 4.

In addition to the delivery rate changes arising from the $1.0 million revenue requirement decrease, core market customers will also experience rate changes in 2005 related to the Revenue Stabilization Adjustment Mechanism (RSAM) rider which is expected to go down from the 2004 level by $0.052 per gigajoule and an increase in revenue requirement of $0.002 per gigajoule due to earnings deficit sharing as determined in accordance with the earnings sharing mechanism. There may also be flow-through of cost of gas. Cost of gas changes are dependent on the commodity market and subject to considerable volatility in natural gas commodity markets in which a cold weather snap or unexpected negative news can change the commodity market outlook quite quickly. The net effect for residential customers of the decreases to RSAM rider and the delivery rate along with the increase for the 2004 earnings deficit sharing is a decrease of 0.5% of the annual bill.

The final rates for 2005 may be subject to further adjustments for changes in the allowed return on common equity ("ROE"). The financial calculations for 2005 in the enclosed materials have been made using an ROE of 9.15%, a recent estimate of the ROE that would be in effect if ROE were set using current Long Canada Bond yields. Revisions to the rates relating to the approved ROE for 2005 varying from 9.15% will be in addition to the rate adjustments reflected in these Annual Review materials.

SUMMARY OF 2005 REVENUE REQUIREMENT DECREASE

		($ Millions)
Volumes/Revenue Related		
• Change in Use rates for Rates 1/2/3/23	($0.5)	
• Customer growth and Industrial revenue changes	(4.2)	($4.7)
O & M Related		
• Higher O&M per formula	4.1	
• Change in Pension and Insurance forecast	(1.8)	2.3
Other Items		
• Higher Property Taxes	0.2	
• Lower Depreciation and Amortization	(0.8)	
• Higher Interest Expense	1.9	
• Large Corporations Tax Rate Reduction	(0.9)	
• Higher Other Revenues (primarily SCP related)	(3.7)	
• Lower Income Taxes and Others	(1.8)	
• Higher Rate Base due to Plant Additions	4.4	(0.7)
Revenue Decrease before Coastal Facilities Lease and Exogenous Items		(3.1)
Accounting Change – Coastal Facilities Lease		1.1
Exogenous Items – OSC Certification and BCUC Levies		1.0
Total Revenue Decrease (Section A, Tab 1, Page 5, Column 6, Line 15)		($1.0)

TERASEN GAS INC.

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005 Core	2005 Non-Core	2005 Bypass and Special Rates	2005 Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RATE CHANGE REQUIRED						
2							
3	Gas Sales and Transportation Revenue,						
4	At Prior Year's Rates	$1,380,301	$1,319,679	$56,590	$12,768	$1,389,037	$8,736
5							
6	Add - Other Revenue Related to SCP Third Party						
7	Revenue / Terasen Gas (Vancouver Island)	12,845	0	0	15,991	15,991	3,146
8							
9	Total Revenue	1,393,146	1,319,679	56,590	28,759	1,405,028	11,882
10							
11	Less - Cost of Gas	(923,993)	(907,040)	(1,521)	(363)	(908,924)	15,069
12							
13	Gross Margin	$469,153	$415,696	$55,069	$28,396	$496,104	$26,951
14							
15	Revenue Deficiency (Surplus)	$19,150	($927)	($124)	$0	($1,051)	
16							
17	Revenue Deficiency (Surplus) as a % of Gross Margin	4.08%	-0.22%	-0.23%	0.00%	-0.21%	
18							
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.37%	-0.07%	-0.22%	0.00%	-0.07%	

TERASEN GAS INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005 Existing Rates	2005 Adjustments	2005 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$2,816,944	$2,922,348	$0	$2,922,348	$105,404	- Tab A - 3, Page 7.1
2	CPCNs	10,117	53,749	0	53,749	43,632	- Tab A - 3, Page 7.1
3							
4	Additions	112,914	117,728	0	117,728	4,814	- Tab A - 3, Page 7.1
5	Disposals	(21,139)	(20,340)	0	(20,340)	799	- Tab A - 3, Page 7.1
6							
7	Plant in Service, Ending	2,918,836	3,073,485	0	3,073,485	154,649	
8							
9	Add - Intangible Plant	837	837	0	837	0	
10							
11		2,919,673	3,074,322	0	3,074,322	154,649	
12							
13	Contributions In Aid of Construction	(149,325)	(153,989)	0	(153,989)	(4,664)	- Tab A - 3, Page 8
14							
15	Less - Accumulated Depreciation	(566,585)	(625,051)	0	(625,051)	(58,466)	- Tab A - 3, Page 13
16							
17							
18	Net Plant in Service, Ending	$2,203,763	$2,295,282	$0	$2,295,282	$91,519	
19							
20							
21	Net Plant in Service, Beginning	$2,177,251	$2,266,265	$0	$2,266,265	$89,014	- Tab A - 3, Page 9
22							
23							
24	Net Plant in Service, Mid-Year	$2,190,507	$2,280,774	$0	$2,280,774	$90,267	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(750)	(2)	0	(2)	748	
27	Work in Progress, No AFUDC	4,000	12,358	0	12,358	8,358	
28	Unamortized Deferred Charges	25,610	6,724	0	6,724	(18,886)	- Tab A - 3, Page 11.1
29	Cash Working Capital	(18,804)	(22,887)	4	(22,883)	(4,079)	- Tab A - 3, Page 12
30	Other Working Capital	101,177	121,715	0	121,715	20,538	- Tab A - 3, Page 12
31	Deferred Income Tax, Mid-Year	(364)	(364)	0	(364)	0	
32	Capital Efficiency Mechanism	0	0	0	0	0	
33	LILO Benefit	(1,510)	(2,564)	0	(2,564)	(1,054)	
34	Utility Rate Base	$2,299,866	$2,395,754	$4	$2,395,758	$95,892	

TERASEN GAS INC.

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005 Existing Rates	2005 ----Revised Rates----- Revised Revenue	2005 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	120,165	119,302	0	119,302	(863)	- Tab A - 4, Page 12
3	Transportation	131,274	105,684	0	105,684	(25,590)	- Tab A - 4, Page 12
4		251,439	224,986	0	224,986	(26,453)	- Tab A - 4, Page 12
5							
6	Average Rate per GJ						
7	Sales	$11.106	$11.067	$0.000	$11.059	($0.047)	
8	Transportation	$0.494	$0.650	$0.000	$0.649	$0.155	
9	Average	$5.566	$6.174	$0.000	$6.169	$0.603	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,317,543	$1,320,326	$0	$1,320,326	$2,783	- Tab A - 4, Page 13
13	- Increase	17,005	0	(926)	(926)	(17,931)	
14							
15	Transportation - Existing Rates	62,758	68,711	0	68,711	5,953	- Tab A - 4, Page 13
16	- Increase	2,145		(125)	(125)	(2,270)	
17	**Total**	1,399,451	1,389,037	(1,051)	1,387,986	(11,465)	
18							
19	Cost of Gas Sold (Including Gas Lost)	923,993	908,924	0	908,924	(15,069)	- Tab A - 4, Page 14.1
20							
21	**Gross Margin**	475,458	480,113	(1,051)	479,062	3,604	
22							
23	Operation and Maintenance	159,417	161,729	0	161,729	2,312	- Tab A - 5, Page 2
24	Vehicle / Coastal Facilities Lease	6,372	1,915	0	1,915	(4,457)	- Section B, Tab 7
25	Property and Sundry Taxes	39,420	39,573	0	39,573	153	- Tab A - 6, Page 4
26	Depreciation and Amortization	78,885	79,777	0	79,777	892	- Tab A - 6, Page 7
27	Other Operating Revenue	(22,633)	(26,375)	0	(26,375)	(3,742)	- Tab A - 4, Page 16
28		261,461	256,619	0	256,619	(4,842)	
29	Utility Income Before Income Taxes	213,997	223,494	(1,051)	222,443	8,446	
30							
31	Income Taxes	40,219	39,218	(362)	38,856	(1,363)	- Tab A - 1, Page 8
32							
33	**EARNED RETURN**	$173,778	$184,276	($689)	$183,587	$9,809	
34							
35	**UTILITY RATE BASE**	$2,299,866	$2,395,754	$4	$2,395,758	$95,892	
36							
37	**RATE OF RETURN ON UTILITY RATE BASE**	7.556%	7.690%		7.663%	0.11%	

TERASEN GAS INC.

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005 Existing Rates	2005 ----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$173,778	$184,276	($689)	$183,587	$9,809	- Tab A - 1, Page 7
3	Deduct - Interest on Debt	(104,319)	(111,230)	0	(111,230)	(6,911)	
4	Add- Non-Tax Ded. Expense (Net)	262	(367)	0	(367)	(629)	- Tab A - 6, Page 6
5							
6	Accounting Income After Tax	69,721	72,679	(689)	71,990	2,269	
7	Add (Deduct) - Timing Differences	(6,616)	(10,273)	0	(10,273)	(3,657)	- Tab A - 6, Page 6
8	Add - Large Corporation Tax	3,415	3,020	12	3,032	(383)	- Tab A - 6, Page 9
9							
10	Taxable Income After Tax	$66,520	$65,426	($677)	$64,749	($1,771)	
11							
12	Income Tax Rate (Current Tax)	35.620%	35.620%	35.620%	35.620%	0.000%	
13	1 - Current Income Tax Rate	64.380%	64.380%	64.380%	64.380%	0.000%	
14							
15	Taxable Income (L10 : L13)	$103,324	$101,624	($1,051)	$100,573	($2,751)	
16							
17	Income Tax - Current (L12 x L15)	$36,804	$36,198	($374)	$35,824	($980)	
18							
19	- Large Corporation Tax	3,415	3,020	12	3,032	(383)	- Tab A - 6, Page 9
20							
21	Total	$40,219	$39,218	($362)	$38,856	($1,363)	- Tab A - 1, Page 7
22							
23							
24	REVENUE DEFICIENCY						
25	Earned Return	$173,778		($689)	$183,587	$9,809	- Tab A - 1, Page 7
26	Add - Income Taxes	40,219		(362)	38,856	(1,363)	- Tab A - 1, Page 7
27	Deduct - Utility Income Before Taxes,						
28	Existing Rates	(194,847)		0	(223,494)	(28,647)	- Tab A - 1, Page 7
29	Corporate Capital Tax	0		0	0	0	
30							
31	Deficiency After Corporate Capital Tax	$19,150		($1,051)	($1,051)	($20,201)	

TERASEN GAS INC.

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2005 AT 2004 RATES							
2	Long-Term Debt			$1,444,684	60.30%	7.255%	4.375%	
3	Unfunded Debt			160,471	6.70%	4.000%	0.268%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			790,599	33.00%	9.233%	3.047%	
6								
7				$2,395,754	100.00%		7.690%	
8								
9	2005 REVISED RATES							
10	Long-Term Debt			$1,444,684	60.30%	7.255%	4.375%	$104,812
11	Unfunded Debt		$160,471					
12	Adjustment, Revised Rates		3	160,474	6.70%	4.000%	0.268%	6,418
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			790,600	33.00%	9.150%	3.020%	72,357
15								
16				$2,395,758	100.00%		7.663%	$183,587
17								
18	2004 APPROVED							
19	Long-Term Debt			$1,315,417	57.20%	7.373%	4.217%	$96,990
20	Unfunded Debt		$225,292					
21	Adjustment, Revised Rates		201	225,493	9.80%	3.250%	0.319%	7,329
22	Preference Shares			0	0.00%	0.000%	0.000%	0
23	Common Equity			758,957	33.00%	9.150%	3.020%	69,459
24								
25				$2,299,867	100.00%		7.556%	$173,778
26								
27	2005 CHANGE FROM 2004 APPROVED							
28	Long-Term Debt			$129,267	3.10%	-0.118%	0.158%	$7,822
29	Unfunded Debt		($64,821)					
30	Adjustment, Revised Rates		(198)	(65,019)	-3.10%	0.750%	-0.051%	(911)
31	Preference Shares			0	0.00%	0.000%	0.000%	0
32	Common Equity			31,643	0.00%	0.000%	0.000%	2,898
33								
34				$95,891	0.00%		0.107%	$9,809

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2005 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-2 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
2005 COST DRIVERS

The table below shows the Cost Driver forecasts which are used for setting the 2005 Targets as prescribed in BCUC Order No. G-51-03.

	2003 Actual	2004 Projected	2005 Forecast	
Cost Drivers				
Year End Customer Count	775,516	786,928	797,072	
Customer Additions		11,412	10,144	Note 1
Average Customers Count	770,624	779,498	790,385	
Change in Average Customers		8,874	10,887	Note 2
Percentage of Customer Growth - Average		1.15%	1.40%	
Escalators				
B.C. Inflation (CPI)			2.00%	Note 3
Adjustment Factor			1.00%	Note 4

Explanatory Notes

Note 1 2004 projection and 2005 forecast year end customer counts are explained under Tab 4 - Volumes and Revenues. Year end customer additions are used to calculate Capital Expenditures driven by customer addition.

Note 2 The percentage growth in average customer is used to calculate the formula based O & M Expense and Other Based Capital Expenditures.

Note 3 Pursuant to the provisions of the July 29, 2003 BCUC Decision, the 2005 B.C. inflation forecast will be determined as the average of the forecasts from the Conference Board of Canada, the B.C. Ministry of Finance, the RBC Financial Group, and the Toronto-Dominion Bank.

Based on this formula, the B.C. CPI forecast for 2005 is 2.0%, and represents the average of the forecasts below:

Conference Board of Canada	2.1%	(July 2004)
B.C. Ministry of Finance	1.9%	(Spring 2004)
RBC Financial Group	2.0%	(May 2004)
Toronto-Dominion Bank	2.0%	(July 2004)

(Copies of the forecasts are attached as Attachment A)

Note 4 Pursuant to the provisions of BCUC Order G-51-03, the adjustment factor will be 50% of CPI for 2005, equal to 1%.

TAB A-2 2005 COST DRIVERS

ATTACHMENT A

Official Forecasts of British Columbia Consumer Price Index
August 23, 2004

Source	Forecast Date	Percent Change 2004	Percent Change 2005
British Columbia Ministry of Finance	Spring 2004	1.6	1.9
Conference Board of Canada	July 15, 2004	2.1	2.1
RBC Financial Group	May 2004	1.0	2.0
TD Bank Financial Group	July 22, 2004	1.8	2.0
Average		**1.625**	**2.0**

Table 3.7.2 Components of British Columbia Real GDP at Market Prices

	2002	2003[e]	Forecast 2004	2005	2006	2007	2008
			1997$ billion; chain-weighted				
Personal Expenditure on Goods and Services	83.0	84.7	87.4	90.3	92.7	95.2	97.7
(% change)	3.1	2.1	3.1	3.3	2.7	2.7	2.6
- Goods	36.1	36.3	37.5	38.7	39.6	40.6	41.5
(% change)	4.0	0.5	3.3	3.3	2.4	2.4	2.3
- Services	47.0	48.5	49.9	51.5	53.0	54.6	56.2
(% change)	2.4	3.2	2.9	3.3	2.8	3.0	2.9
Government Current Expenditures on Goods and Services	25.1	25.3	24.9	25.2	25.9	26.6	27.2
(% change)	2.1	0.8	-1.6	1.4	2.8	2.5	2.4
Investment in Fixed Capital	25.0	26.2	27.9	29.0	29.9	31.2	32.7
(% change)	-0.9	4.6	6.5	4.0	3.1	4.5	4.6
Final Domestic Demand	**133.2**	**136.2**	**140.0**	**144.4**	**148.4**	**152.9**	**157.4**
(% change)	**2.1**	**2.3**	**2.8**	**3.1**	**2.8**	**3.0**	**3.0**
Exports Goods & Services	56.6	56.4	58.8	60.8	62.8	65.0	67.2
(% change)	-0.1	-0.4	4.2	3.4	3.3	3.4	3.5
Imports Goods & Services	61.9	63.3	66.0	68.2	70.0	72.3	74.3
(% change)	0.7	2.3	4.2	3.3	2.7	3.2	2.9
Inventory Change	0.4	0.9	1.0	1.0	1.0	1.0	0.7
Statistical Discrepancy	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Real GDP at Market Prices	**128.2**	**130.1**	**133.7**	**137.8**	**142.0**	**146.4**	**150.8**
(% change)	**2.4**	**1.5**	**2.8**	**3.1**	**3.1**	**3.1**	**3.0**

[e] Figures for 2003 are Ministry of Finance estimates.

Table 3.7.3 Components of Nominal Income and Expenditure

	2002	2003	Forecast [illegible]	2005	2006	2007	2008
Labour Income[1] ($ million)	71,819	74,066 [e]	77,240	80,677	84,449	88,396	92,565
(% change)	2.5	3.1	4.3	4.5	4.7	4.7	4.7
Personal Income ($ million)	111,852	115,132 [e]	119,713	124,840	130,167	135,715	141,586
(% change)	1.8	2.9	4.0	4.3	4.3	4.3	4.3
Corporate Profits Before Taxes ($ million)	10,563	10,676 [e]	11,403	12,331	13,284	14,326	15,431
(% change)	-5.8	1.1	6.8	8.1	7.7	7.8	7.7
Retail Sales ($ million)	40,273	41,094 [e]	42,905	44,987	47,095	49,223	51,485
(% change)	6.0	2.0	4.4	4.9	4.7	4.5	4.6
Housing Starts	21,625	26,174	26,949	26,966	27,536	27,855	27,987
(% change)	25.5	21.0	3.0	0.1	2.1	1.2	0.5
Residential Investment[2] ($ million)	9,012	10,241 [e]	10,894	11,403	12,034	12,651	13,289
(% change)	19.6	13.6	6.4	4.7	5.5	5.1	5.0
B.C. Consumer Price Index (1992 = 100)	117.9	120.4	122.4	124.6	127.1	129.7	132.2
(% change)	2.3	2.1	1.6	1.9	2.0	2.0	2.0

[e] Figures are Ministry of Finance estimates.

[1] Domestic basis; wages, salaries and supplementary labour income.

[2] Includes renovations and improvements.

[redacted]

[redacted]	[redacted]	147,601	150,722	151,974	153,193	155,025	156,887	158,701	160,292	[redacted]	150,872	157,726
		2.3	*2.1*	*0.8*	*0.8*	*1.2*	*1.2*	*1.2*	*1.0*		*5.9*	*4.5*
[redacted]	[redacted]	134,834	137,685	138,798	139,762	141,404	143,058	144,659	146,038	[redacted]	137,770	143,790
		2.3	*2.1*	*0.8*	*0.7*	*1.2*	*1.2*	*1.1*	*1.0*		*5.7*	*4.4*
[redacted]	[redacted]	123,457	124,396	125,136	125,865	126,853	127,631	128,445	129,157	[redacted]	124,713	128,021
		1.0	*0.8*	*0.6*	*0.6*	*0.8*	*0.6*	*0.6*	*0.6*		*3.0*	*2.7*
[redacted]	[redacted]	1.212	1.229	1.235	1.241	1.246	1.252	1.258	1.264	[redacted]	1.229	1.255
		0.4	*1.4*	*0.5*	*0.5*	*0.4*	*0.5*	*0.5*	*0.5*		[illegible]	[illegible]
[redacted]	[redacted]	1.092	1.107	1.109	1.110	1.115	1.121	1.126	1.131	[redacted]	1.105	1.123
		1.3	*1.3*	*0.2*	*0.1*	*0.4*	*0.6*	*0.5*	*0.4*		*2.6*	*1.7*
[redacted]	[redacted]	670.2	675.5	680.5	685.6	691.0	695.9	701.0	706.2	[redacted]	677.9	698.5
		0.2	*0.8*	*0.7*	*0.7*	*0.8*	*0.7*	*0.7*	*0.7*		*1.7*	*3.0*
[redacted]	[redacted]	117,125	117,837	119,376	120,895	122,583	124,167	125,789	127,155	[redacted]	118,808	124,924
		1.8	*0.6*	*1.3*	*1.3*	*1.4*	*1.3*	*1.3*	*1.1*		*4.0*	*5.1*
[redacted]	[redacted]	90,628	91,274	92,468	93,659	95,145	96,405	97,668	98,721	[redacted]	92,007	96,985
		1.9	*0.7*	*1.3*	*1.3*	*1.6*	*1.3*	*1.3*	*1.1*		*3.9*	*5.4*
[redacted]	[redacted]	–10.08	–10.44	–10.61	–10.38	–10.06	–10.02	–10.06	–10.15	[redacted]	–10.38	–10.08
[redacted]	[redacted]	3,396	3,411	3,419	3,429	3,440	3,452	3,462	3,472	[redacted]	3,414	3,456
		0.4	*0.4*	*0.2*	*0.3*	*0.3*	*0.4*	*0.3*	*0.3*		*1.4*	*1.3*
[redacted]	[redacted]	2,220	2,228	2,245	2,246	2,261	2,268	2,276	2,283	[redacted]	2,235	2,272
		0.0	*0.4*	*0.7*	*0.1*	*0.6*	*0.3*	*0.3*	*0.3*		*1.5*	*1.7*
[redacted]	[redacted]	2,050	2,057	2,073	2,081	2,087	2,097	2,109	2,116	[redacted]	2,065	2,102
		–0.4	*0.4*	*0.8*	*0.4*	*0.3*	*0.5*	*0.6*	*0.3*		*2.1*	*1.8*
[redacted]	[redacted]	7.7	7.7	7.6	7.4	7.7	7.5	7.3	7.3	[redacted]	7.6	7.5
[redacted]	[redacted]	42,419	42,704	43,152	43,606	44,144	44,746	45,399	45,892	[redacted]	42,970	45,045
		3.5	*0.7*	*1.0*	*1.1*	*1.2*	*1.4*	*1.5*	*1.1*		*4.8*	*4.8*
[redacted]	[redacted]	30,800	36,663	28,956	27,701	26,553	24,738	24,197	23,206	[redacted]	31,030	24,674
		8.5	*19.0*	*–21.0*	*–4.3*	*–4.1*	*–6.8*	*–2.2*	*–4.1*		*18.6*	*–20.5*

[redacted]

British Columbia

		1998	1999	2000	2001	2002	2003	2004	2005
Gross domestic product	$ millions	115,641	120,921	131,086	132,050	135,552	142,418	147,972	155,075
	% change	1.1	4.6	8.4	0.7	2.7	5.1	3.9	4.8
Real GDP	$1997 millions	115,883	119,604	125,314	125,191	128,151	130,914	134,841	139,561
	% change	1.3	3.2	4.8	-0.1	2.4	2.2	3.0	3.5
Employment	thousands	1,870.2	1,906.4	1,949.1	1,942.4	1,973.4	2,023.3	2,059.7	2,098.9
	% change	0.1	1.9	2.2	-0.3	1.6	2.5	1.8	1.9
Labour force	thousands	2,051.2	2,079.1	2,099.7	2,103.5	2,157.8	2,202.1	2,235.1	2,273.1
	% change	0.5	1.4	1.0	0.2	2.6	2.1	1.5	1.7
Unemployment rate	%	8.8	8.3	7.2	7.7	8.5	8.1	7.8	7.7
Personal disposable income	$ millions	74,388	77,412	81,538	84,345	87,242	88,921	92,478	97,102
	% change	1.9	4.1	5.3	3.4	3.4	1.9	4.0	5.0
Retail sales	$ millions	33,049	33,684	35,821	37,979	40,273	41,006	42,811	44,823
	% change	-2.0	1.9	6.3	6.0	6.0	1.8	4.4	4.7
Housing starts	units	20,300	16,308	14,358	17,167	21,742	26,117	27,553	27,278
	% change	-30.2	-19.7	-12.0	19.6	26.7	20.1	5.5	-1.0
[redacted]	1992=100	110.0	111.2	113.3	115.2	117.9	120.4	121.6	124.0
	% change	0.3	1.1	1.9	1.7	2.3	2.1	[redacted]	[redacted]

Alberta

		1998	1999	2000	2001	2002	2003	2004	2005
Gross domestic product	$ millions	107,439	117,080	143,721	151,173	149,998	170,631	177,115	184,731
	% change	0.4	9.0	22.8	5.2	-0.8	13.8	3.8	4.3
Real GDP	$1997 millions	112,677	114,227	120,754	123,961	125,775	128,490	132,730	136,978
	% change	5.3	1.4	5.7	2.7	1.5	2.2	3.3	3.2
Employment	thousands	1,515.4	1,553.3	1,588.2	1,632.1	1,673.8	1,721.7	1,763.0	1,782.4
	% change	3.9	2.5	2.2	2.8	2.6	2.9	2.4	1.1
Labour force	thousands	1,605.1	1,647.9	1,671.4	1,710.7	1,767.6	1,814.9	1,853.0	1,871.5
	% change	3.7	2.7	1.4	2.4	3.3	2.7	2.1	1.0
Unemployment rate	%	5.6	5.7	5.0	4.6	5.3	5.1	4.9	4.8
Personal disposable income	$ millions	59,073	61,845	67,691	75,676	79,528	82,540	85,842	89,962
	% change	6.4	4.7	9.5	11.8	5.1	3.8	4.0	4.8
Retail sales	$ millions	28,069	29,335	31,712	34,602	37,457	38,931	40,761	42,473
	% change	4.2	4.5	8.1	9.1	8.3	3.9	4.7	4.2
Housing starts	units	27,283	25,183	26,300	29,000	38,892	36,458	35,620	34,622
	% change	12.7	-7.7	4.4	10.3	34.1	-6.3	-2.3	-2.8
Consumer price index	1992=100	110.7	113.4	117.4	120.1	124.2	129.7	131.6	134.0
	% change	1.1	2.4	3.5	2.3	3.4	4.4	1.5	1.8

RBC - PROVINCIAL OUTLOOK - MAY 2004

PROVINCIAL REAL GDP
Per cent change

	2001	2002	2003	2004f	2005f
CANADA	1.8	3.4	2.0	2.8	3.5
N. & L.	0.9	15.4	6.5	1.9	2.1
P.E.I.	0.2	5.7	1.9	2.0	3.0
N.S.	2.6	4.4	0.9	2.3	2.8
N.B.	1.0	4.0	2.6	2.6	3.2
Quebec	1.8	4.0	1.6	2.8	3.5
Ontario	1.8	3.6	1.3	2.4	3.4
Manitoba	1.2	2.1	1.4	3.0	3.3
Sask.	-0.7	-1.5	4.5	3.4	3.0
Alberta	2.7	1.5	2.2	4.0	3.8
B.C.	-0.1	2.4	2.2	3.1	4.1
Yukon	1.8	0.2	0.2	2.0	2.4
N.W.T.	23.2	4.0	10.6	5.7	9.2
Nunavut	6.3	3.0	-10.5	7.0	3.5

f: forecast by TD Economics as at July 2004
GDP: gross domestic product ; Source: Statistics Canada

REAL PERSONAL DISPOSABLE INCOME (PDI)
Annual average per cent change

	2001	2002	2003	2004f	2005f
CANADA	2.6	2.7	1.0	2.9	3.5
N. & L.	2.6	2.9	2.5	1.3	1.8
P.E.I.	0.4	4.1	-2.6	1.8	2.3
N.S.	2.4	1.1	0.4	1.5	2.1
N.B.	1.0	0.3	0.8	2.0	2.5
Quebec	2.8	4.1	1.7	2.8	2.8
Ontario	1.1	3.1	0.9	2.8	3.5
Manitoba	1.4	2.2	-0.6	2.8	3.2
Sask.	0.5	-1.0	2.2	2.1	2.9
Alberta	9.6	2.6	1.8	3.9	4.5
B.C.	1.9	1.0	0.3	3.5	3.9
Yukon	1.5	3.3	1.1	3.0	3.5
N.W.T.	6.4	8.5	3.7	5.1	4.1
Nunavut	7.6	4.5	-0.1	3.0	3.5

f: forecast by TD Economics as at July 2004
Source: Statistics Canada

EMPLOYMENT
Annual average per cent change

	2001	2002	2003	2004f	2005f
CANADA	1.1	2.2	2.2	1.7	1.6
N. & L.	3.3	1.2	1.8	1.4	0.9
P.E.I.	2.2	1.8	2.5	0.0	1.1
N.S.	0.9	1.2	1.6	1.9	1.3
N.B.	0.0	3.3	-0.2	1.8	1.3
Quebec	1.1	3.4	1.6	1.5	1.4
Ontario	1.5	1.8	2.6	1.8	1.7
Manitoba	0.6	1.6	0.3	1.2	1.3
Sask.	-2.6	2.0	1.0	1.0	1.2
Alberta	2.8	2.6	2.9	2.4	2.0
B.C.	-0.3	1.6	2.5	2.0	1.9

f: forecast by TD Economics as at July 2004
Source: Statistics Canada

UNEMPLOYMENT RATE
Per cent

	2001	2002	2003	2004f	2005f
CANADA	7.2	7.7	7.6	7.3	7.1
N. & L.	16.1	16.9	16.7	16.5	16.6
P.E.I.	11.8	12.1	11.2	11.9	11.8
N.S.	9.7	9.7	9.3	9.1	8.9
N.B.	11.2	10.4	10.6	10.0	10.0
Quebec	8.7	8.6	9.1	8.4	8.1
Ontario	6.3	7.1	7.0	6.8	6.6
Manitoba	5.0	5.2	5.0	5.1	4.9
Sask.	5.8	5.7	5.6	5.3	5.4
Alberta	4.6	5.3	5.1	4.8	4.7
B.C.	7.7	8.5	8.1	7.7	7.6

f: forecast by TD Economics as at July 2004
Source: Statistics Canada, TD Economics

[redacted]
Annual average per cent change

	2001	2002	2003	2004f	2005f
CANADA	2.6	2.2	2.7	1.7	2.1
N. & L.	1.1	2.4	2.9	1.6	2.1
P.E.I.	2.6	2.7	3.5	1.5	2.2
N.S.	1.8	3.0	3.4	1.6	1.9
N.B.	1.7	3.4	3.4	1.3	2.0
Quebec	2.4	2.0	2.5	1.7	1.9
Ontario	3.1	2.0	2.6	1.9	2.1
Manitoba	2.6	1.6	1.8	1.3	1.9
Sask.	3.1	2.8	2.3	1.7	2.2
Alberta	2.3	3.4	4.4	1.5	2.3
[redacted]	1.7	2.3	2.1	1.8	2.0

f: forecast by TD Economics as at July 2004
Source: Statistics Canada

HOUSING STARTS
Thousands of units

	2001	2002	2003f	2004f	2005f
CANADA	162.7	205.0	218.4	220.0	185.0
N. & L.	1.8	2.4	2.7	2.7	2.1
P.E.I.	0.7	0.8	0.8	0.9	0.7
N.S.	4.1	5.0	5.1	4.4	3.9
N.B.	3.5	3.9	4.5	3.7	3.2
Quebec	27.7	42.5	50.3	53.0	42.0
Ontario	73.3	83.6	85.2	83.5	69.5
Manitoba	3.0	3.6	7.2	4.4	3.6
Sask.	2.4	3.0	3.3	3.4	3.0
Alberta	29.2	38.8	36.2	32.0	27.0
B.C.	17.2	21.6	26.2	32.0	30.0

f: forecast by TD Economics as at July 2004
Source: Canada Mortgage and Housing Corporation

TD - REGIONAL ECONOMIC OUTLOOK July 22, 2004

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2005 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-3 INDEX

2005 RATE BASE

The 2005 Rate base is forecast to be $2.396 billion. Rate Base is composed of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, cash working capital, other working capital, deferred income tax, and LILO benefit.

The 2005 Rate Base includes full year impacts of the 2004 projected plant activities including:

- 2004 CPCN Opening Additions of $14.1 million
- Adjusted Formula-Based Capital Additions of $118.7 million
- Plant Depreciation and CIAOC Amortization of $77.5 million

Details of the 2004 projected plant balances can be found in Section A, Tab 3, Pages 7.2 and 7.3.

Also, the 2005 Rate Base includes 2005 activities including:

- 2005 CPCN Opening Additions of $53.7 million (including $50.3 million Coastal Facilities transferred to rate base at January, 1, 2005)
- Base Capital Additions of $117.7 million
- Plant Depreciation and CIAOC Amortization of $80.8 million
- Various changes in deferred charges, working capital and other items increasing rate base by a net amount of $5.6 million.

Details of the 2005 forecasted plant balances can be found in Section A, Tab 3, Pages 7 and 7.1.

2005 CAPITAL EXPENDITURES

The 2005 Capital Expenditures are based on the capital expenditure formula (approved by Commission Order No. G-51-03) plus forecast CPCNs. The capital expenditure formula is composed of two cost components: Customer Addition Driven Capital and Other Base Capital driven by average number of customers.

Per Commission Order No. G-51-03, base capital expenditure amounts will not be rebased to actual amounts during the term. For the 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 customers as this information becomes known. There is no true up for CPI.

During the 2003 annual review, Terasen Gas had forecast 8,604 customer additions along with 777,779 average number of customers for 2004.The current projection for 2004 is 11,412 and 779,498 respectively. Accordingly, the total formula based capital expenditures for 2004 derived from the projected customer addition numbers has increased from $85.4 million to $91.5 million. Supporting calculations can be found at Tab 3, Page 4.

The 2005 Capital Expenditure is calculated using the 2005 Forecast Unit Cost multiplied by customer accounts cost drivers. The detail calculation is shown on Tab 3, Page 4.

- 2005 Forecast Unit Cost per Customer =
    - 2004 Unit Cost per Customer x ([1 + (CPI - Adjustment Factor)
- 2005 Capital Expenditure =
    - 2005 Forecast Unit Cost per customer x Cost Driver
    - The Cost Driver for:
        - Customer Addition Driven Capital is Number of Customer Additions
        - Other Base Capital is Average Number of Customers
- Special Projects - 2005 CPCN Capital Expenditures includes:
    - Transmission Pipeline Integrity Plan: $3.7M
    - Fraser River Crossing: $20.0M
    - Coastal Facilities: $50.3M (discussed below)

As discussed under Section B, Tab 7, Terasen Gas proposes to transfer to rate base at January 1, 2005 an estimated $50.3 million representing the outstanding balance of the Coastal Facilities Project. This proposed transfer is brought on by an accounting rule change. Because Terasen Gas proposes to calculate the depreciation of the Coastal Facilities assets at the prescribed BCUC depreciation rate of 1.5%, commencing in 2005, Opening CPCN treatment accommodates this objective.

2005 PLANT ADDITIONS

The 2005 Plant Additions are comprised of the 2005 formula-driven Base Capital plant costs including AFUDC, overhead capitalized for the year, and opening 2005 CPCN Additions. The opening 2005 CPCN plant additions are the CPCN plant costs put in-service in 2004. The reconciliation of capital expenditures to plant additions is shown on Section A, Tab 3, Page 5.

The 2005 Plant Additions allowed by the terms of the Settlement is $171.477 million. The Plant Addition summary is shown below:

2005 Plant Additions	
Formula-based Base Capital	$ 91.393 million
Overhead Capitalized	$ 26.335 million
Opening CPCN - Coastal Facilities	$50.258 million
Opening CPCN – Other Additions	$ 3.491 million
Total 2005 Plant **Additions**	$ 171.477 million

Consistent with the terms of the Settlement, the 2005 Contributions in Aid of Construction Additions ("CIAOC") are formula-based. The software tax savings are based on the software plant additions arising from the base capital additions formula. The Service Line Installation Fee is calculated based on $215 per service line. The other CIAOC consisting of main extensions, excess service line charges, billable alterations, meter & regulator equipment work, and other CIAOC have been calculated based on the PBR Formula. CIAOC is subject to the same adjustment and true-up process as base capital additions. Therefore, the CIAOC additions for 2004 have been adjusted based on projected 2004 customer counts. The 2005 CIAOC and 2004 formula updated CIAOC schedules can be found in Section A, Tab 3, Page 8 and Page 8.1, respectively.

TERASEN GAS INC.
CAPITAL EXPENDITURES
FOR THE YEARS ENDING DECEMBER 31, 2004 and 2005

Line. No.	Particulars	PBR Settlement 2003	Approved 2004	Adjusted 2004	Forecast 2005
	(1)	(2)	(3)	(4)	(5)
1	Forecast CPI (BC)		1.70%		2.00%
2	Adjustment Factor		0.85%		1.00%
3					
4	CPI - Adjustment Factor		100.85%		101.00%
5					
6					
7	**CUSTOMER ADDITION DRIVEN CAPITAL EXPENDITURES**				
8					
9	Customer Addition Driven Capital Expenditures Per Customer Addition	$2,093.04	$2,110.83	$2,110.83	$2,131.94
10					
11	Number of Customers Additions		8,604	11,412	10,144
12					
13	**Target Customer Addition Driven Capital Expenditures ($000)**		**$18,162**	**$24,089**	**$21,626**
14					
15					
16	**OTHER BASE CAPITAL EXPENDITURES**				
17					
18	Other Base Capital Expenditures Per Customer	$85.69	$86.42	$86.42	$87.28
19					
20	Average Number of Customers		777,779	779,498	790,385
21					
22	**Target Other Base Capital Expenditures ($000)**		**$67,216**	**$67,364**	**$68,985**
23					
24					
25					
26	**SUMMARY CAPITAL EXPENDITURES ($000)**				
27					
28	Target Customer Addition Driven Capital Expenditures		$18,162	$24,089	$21,626
29	Target Other Base Capital Expenditures		67,216	67,364	68,985
30					
31	Total Target Base Capital Expenditures		$85,378	$91,453	$90,611
32					
33					
34	**Total Base Capital Additions excluding Forecast CPCN Additions ($000)**		**$85,378**	**$91,453**	**$90,611**

TERASEN GAS INC.
CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2004 and 2005
($000)

Line No.	Particulars	Approved 2004	Adjusted 2004	Forecast 2005
	(1)	(2)	(3)	(4)
1	**CAPITAL EXPENDITURES**			
2				
3	Base Capital Expenditures			
4	Customer Addition Driven Capital Expenditures	$18,162	$24,089	$21,626
5	Other Base Capital Expenditures	67,216	67,364	68,985
6				
7	Total Base Capital Expenditures	$85,378	$91,453	$90,611
8				
9	Special Projects - CPCNs			
10	WMS/PM	$0	$506	$0
11	Transmission Pipeline Integrity Plan	2,777	2,785	3,723
12	Coastal Facilities	0	0	50,258
13	Fraser River Crossing	0	0	20,000
14				
15	Total CPCNs	$2,777	$3,291	$73,981
16				
17				
18	TOTAL CAPITAL EXPENDITURES	$88,155	$94,744	$164,592
19				
20				
21	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
22				
23	Base Capital			
24	Base Capital Expenditures	$85,378	$91,453	$90,611
25	Add - Opening WIP	11,891	11,891	11,547
26	Less - Opening WIP adjustment	0	0	0
27	Less - Closing WIP	(11,251)	(11,547)	(11,685)
28				
29	Add - AFUDC	887	908	919
30	Add - Overhead Capitalized	26,009	26,009	26,335
31				
32	TOTAL BASE CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$112,914	$118,714	$117,728
33				
34	Special Projects - CPCNs			
35	CPCNs Expenditures	$2,777	$3,291	$73,981
36	Add - Opening WIP	10,912	14,193	3,741
37	Less - Closing WIP	(3,671)	(3,741)	(24,055)
38				
39	Add - AFUDC	99	332	82
40				
41	TOTAL CPCN ADDITIONS TO OPENING GAS PLANT IN SERVICE	$10,117	$14,075	$53,749
42				
43				
	TOTAL PLANT ADDITIONS	$123,031	$132,789	$171,477

TERASEN GAS INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005 Existing Rates	2005 Adjustments	2005 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$2,816,944	$2,922,348	$0	$2,922,348	$105,404	- Tab A - 3, Page 7.1
2	CPCNs	10,117	53,749	0	53,749	43,632	- Tab A - 3, Page 7.1
3							
4	Additions	112,914	117,728	0	117,728	4,814	- Tab A - 3, Page 7.1
5	Disposals	(21,139)	(20,340)	0	(20,340)	799	- Tab A - 3, Page 7.1
6							
7	Plant in Service, Ending	2,918,836	3,073,485	0	3,073,485	154,649	
8							
9	Add - Intangible Plant	837	837	0	837	0	
10							
11		2,919,673	3,074,322	0	3,074,322	154,649	
12							
13	Contributions In Aid of Construction	(149,325)	(153,989)	0	(153,989)	(4,664)	- Tab A - 3, Page 8
14							
15	Less - Accumulated Depreciation	(566,585)	(625,051)	0	(625,051)	(58,466)	- Tab A - 3, Page 13
16							
17							
18	Net Plant in Service, Ending	$2,203,763	$2,295,282	$0	$2,295,282	$91,519	
19							
20							
21	Net Plant in Service, Beginning	$2,177,251	$2,266,265	$0	$2,266,265	$89,014	- Tab A - 3, Page 9
22							
23							
24	Net Plant in Service, Mid-Year	$2,190,507	$2,280,774	$0	$2,280,774	$90,267	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(750)	(2)	0	(2)	748	
27	Work in Progress, No AFUDC	4,000	12,358	0	12,358	8,358	
28	Unamortized Deferred Charges	25,610	6,724	0	6,724	(18,886)	- Tab A - 3, Page 11.1
29	Cash Working Capital	(18,804)	(22,887)	4	(22,883)	(4,079)	- Tab A - 3, Page 12
30	Other Working Capital	101,177	121,715	0	121,715	20,538	- Tab A - 3, Page 12
31	Deferred Income Tax, Mid-Year	(364)	(364)	0	(364)	0	
32	Capital Efficiency Mechanism	0	0	0	0	0	
33	LILO Benefit	(1,510)	(2,564)	0	(2,564)	(1,054)	
34	Utility Rate Base	$2,299,866	$2,395,754	$4	$2,395,758	$95,892	

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Balance 12/31/2004	CPCN'S	2005 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	401 Franchise Consents	$99	$0	$0	$0	$0	$99
2	402 Other Intangible Plant	835	0	0	0	0	835
3	TOTAL INTANGIBLE PLANT	934	0	0	0	0	934
4							
5	430 Manufact'd Gas - Land	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	438	0	0	0	0	438
7	433 Manufacturing Equipment	139	0	0	0	0	139
8	434 Gas Holders - Manufacturing	358	0	0	0	0	358
9	436 Compressed Equipment	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	309	0	0	0	0	309
11	440/441 Land in Fee Simple and Land Rights	927	0	0	0	0	927
12	442 Structures and Improvements	5,455	0	0	0	0	5,455
13	443 Gas Holders - Storage	16,766	0	592	0	0	17,358
14	446 Compressor Equipment	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0
17	449 Local Storage Equipment	16,734	0	0	0	0	16,734
18	TOTAL MANUFACTURED GAS / LOCAL STORAGE	41,210	0	592	0	0	41,802
19							
20	460 Land in Fee Simple	7,444	0	0	0	0	7,444
21	461 Land Rights	39,506	(14)	1,766	0	0	41,258
22	462 Compressor Structures	14,784	0	404	0	0	15,188
23	463 Measuring Structures	4,276	0	0	0	0	4,276
24	464 Other Structures and Improvements	4,881	0	0	0	0	4,881
25	465 Mains	697,262	2,983	3,225	(310)	0	703,159
26	466 Compressor Equipment	103,078	(5)	49	0	0	103,122
27	467 Measuring and Regulating Equipment	37,033	0	5,365	0	0	42,398
28	468 Communication Structures and Equipment	1,021	0	689	0	0	1,710
29	469 Other Transmission Equipment	0	0	0	0	0	0
30	TOTAL TRANSMISSION PLANT	909,284	2,964	11,498	(310)	0	923,436
31							
32	470 Land	3,248	0	0	0	0	3,248
33	471 Land Rights	679	0	0	0	0	679
34	472 Structures and Improvements	7,029	0	370	0	0	7,399
35	473 Services	541,726	0	20,490	(3,074)	0	559,142
36	474 House Regulators and Meter Installations	137,837	0	9,157	(458)	0	146,536
37	475 Mains	735,038	0	30,854	(3,085)	0	762,807
38	476 Compressor Equipment						
39							
40	-All Other	575	0	0	0	0	575
41	477 Measuring and Regulating Equipment	67,759	0	10,131	(507)	0	77,383
42	478 Meters	188,141	0	15,093	(755)	0	202,479
43	479 Other Distribution Equipment	0	0	0	0	0	0
44	TOTAL DISTRIBUTION PLANT	1,682,032	0	86,095	(7,879)	0	1,760,248

TERASEN GAS INC.

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Balance 12/31/2004	CPCN'S	2005 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	480 Land	$20,936	$0	$21	($5)	$0	$20,952
2	481 Land Rights	0	0	0	0	0	0
3	482 Structures and Improvements						
4							
5	-All Other	43,692	50,258	632	(1,050)	0	93,532
6	483 Office Furniture and Equipment						
7	-Furniture & Equipment	24,266	0	476	(23)	0	24,719
8	-Computers - Hardware	24,241	0	6,544	(3,293)	0	27,492
9	-Computer Software - Non-Infrastructure	38,691	0	2,428	0	0	41,119
10	-Computer Software - Infrastructure/Custom	91,516	527	6,145	(6,809)	0	91,380
11							
12							
13	484 Transportation Equipment	590	0	48	(8)	0	630
14							
15	485 Heavy Work Equipment	366	0	0	0	0	366
16	486 Tools and Work Equipment	27,456	0	2,176	(184)	0	29,448
17	487 Equipment on Customer's Premises	1,813	0	0	0	0	1,813
18	488 Communication Equipment	15,165	0	1,073	(779)	0	15,459
19	489 Other General Equipment						
20	-Stores Material, Capital	0	0	0	0	0	0
21	-All Other	2	0	0	0	0	2
22							
23	TOTAL GENERAL EQUIPMENT	288,735	50,785	19,543	(12,151)	0	346,912
24							
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0
27	497 Allowance for Funds Used						
28	During Construction	0	0	0	0	0	0
29	498 Overhead Charged To Construction	0	0	0	0	0	0
30	499 Plant Suspense	153	0	0	0	0	153
31							
32	TOTAL UNCLASSIFIED PLANT	153	0	0	0	0	153
33							
34	TOTAL CAPITAL	$2,922,348	$53,749	$117,728	($20,340)	$0	$3,073,485

TERASEN GAS INC.

Section A
Tab 3
Page 7.2

GAS PLANT IN SERVICE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Balance 12/31/2003	CPCN'S	Adjusted 2004 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	401 Franchise Consents	99	$0	$0	$0	$0	$99
2	402 Other Intangible Plant	835	0	0	0	0	$835
3	TOTAL INTANGIBLE PLANT	934	0	0	0	0	934
4							
5	430 Manufact'd Gas - Land	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	438	0	0	0	0	438
7	433 Manufacturing Equipment	139	0	0	0	0	139
8	434 Gas Holders - Manufacturing	358	0	0	0	0	358
9	436 Compressed Equipment	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	309	0	0	0	0	309
11	440/441 Land in Fee Simple and Land Rights	927	0	0	0	0	927
12	442 Structures and Improvements	5,455	0	0	0	0	5,455
13	443 Gas Holders - Storage	16,376	0	390	0	0	16,766
14	446 Compressor Equipment	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0
17	449 Local Storage Equipment	16,734	0	0	0	0	16,734
18	**TOTAL MANUFACTURED GAS / LOCAL STORAGE**	40,820	0	390	0	0	41,210
19							
20	460 Land in Fee Simple	7,444	0	0	0	0	7,444
21	461 Land Rights	37,525	28	1,953	0	0	39,506
22	462 Compressor Structures	14,387	6	391	0	0	14,784
23	463 Measuring Structures	4,353	10	0	(87)	0	4,276
24	464 Other Structures and Improvements	4,881	0	0	0	0	4,881
25	465 Mains	682,865	11,085	3,995	(683)	0	697,262
26	466 Compressor Equipment	102,415	465	198	0	0	103,078
27	467 Measuring and Regulating Equipment	33,753	41	5,189	(1,950)	0	37,033
28	468 Communication Structures and Equipment	355	0	666	0	0	1,021
29	469 Other Transmission Equipment	0	0	0	0	0	0
30	**TOTAL TRANSMISSION PLANT**	887,977	11,635	12,392	(2,720)	0	909,284
31							
32	470 Land	3,249	0	0	(1)	0	3,248
33	471 Land Rights	679	0	0	0	0	679
34	472 Structures and Improvements	6,671	0	359	(1)	0	7,029
35	473 Services	522,204	0	21,854	(2,332)	0	541,726
36	474 House Regulators and Meter Installations	130,972	0	9,253	(2,388)	0	137,837
37	475 Mains	706,906	0	30,861	(2,729)	0	735,038
38	476 Compressor Equipment						0
39							0
40	-All Other	575	0	0	0	0	575
41	477 Measuring and Regulating Equipment	58,730	0	9,357	(328)	0	67,759
42	478 Meters	174,566	0	14,968	(1,393)	0	188,141
43	479 Other Distribution Equipment	0	0	0	0	0	0
44	**TOTAL DISTRIBUTION PLANT**	1,604,552	0	86,652	(9,172)	0	1,682,032

GAS PLANT IN SERVICE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Balance 12/31/2003	CPCN'S	Adjusted 2004 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	480 Land	20,921	$0	$20	($5)	$0	$20,936
2	481 Land Rights	0	0	0	0	0	0
3	482 Structures and Improvements						
4	- Coastal Facilities						0
5	-All Other	44,124	0	618	(1,050)	0	43,692
6	483 Office Furniture and Equipment	0					
7	- Furniture and Equipment	23,820	1	465	(20)	0	24,266
8	-Computers - Hardware	24,611	85	6,004	(6,459)	0	24,241
9	-Computer Software - Non-Infrastructure	37,218	0	1,473	0	0	38,691
10	-Computer Software - Infrastructure/Custom	88,351	2,354	7,825	(7,014)	0	91,516
11							
12							
13	484 Transportation Equipment	809	0	42	(261)	0	590
14							
15	485 Heavy Work Equipment	370	0	0	(4)	0	366
16	486 Tools and Work Equipment	25,763	0	1,915	(222)	0	27,456
17	487 Equipment on Customer's Premises	1,813	0	0	0	0	1,813
18	488 Communication Equipment	15,224	0	918	(977)	0	15,165
19	489 Other General Equipment						
20	-Stores Material, Capital	0	0	0	0	0	0
21	-All Other	2	0	0	0	0	2
22							
23	**TOTAL GENERAL EQUIPMENT**	283,026	2,440	19,280	(16,012)	0	288,735
24							
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0
27	497 Allowance for Funds Used						
28	During Construction	0	0	0	0	0	0
29	498 Overhead Charged To Construction	0	0	0	0	0	0
30	499 Plant Suspense	153	0	0	0	0	153
31							
32	**TOTAL UNCLASSIFIED PLANT**	153	0	0	0	0	153
33							
34	**TOTAL CAPITAL**	$2,817,462	$14,075	$118,714	($27,904)	$0	$2,922,348

TERASEN GAS INC.

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars		Projected Balance 12/31/2004	2005 Additions	2005 Retirements	Balance 12/31/2005
	(1)		(2)	(3)	(4)	(5)
1	DSEP/GEAP	211-06	12,671	$0	$0	$12,671
2						
3	NGV Conversion Grants	211-07	0	0	0	0
4						
5	NGV Station Grants	211-08	0	0	0	0
6						
7	Furniture & Equipment	211-10	111	0	0	111
8						
9	Software Tax Savings - Non-Infrastructure	211-11	13,791	1,178	(29)	14,940
10	- Infrastructure/Custom	211-11	40,880	1,805	(2,828)	39,857
11	Service Installation Fee	211-12	16,718	2,181	0	18,899
12						
13	Other	211-00 to 05	64,780	2,752	(21)	67,511
14						
15	TOTAL		148,951	7,916	(2,878)	153,989
16						
17						
18						
19	Amortization	211-15 to 22				
20						
21	- Software Tax Savings - Non-Infrastructure		(9,186)	(2,758)	29	(11,915)
22	- Infrastructure/Custom		(19,276)	(5,110)	2,828	(21,558)
23	- Other		(19,687)	(2,074)	21	(21,740)
24						
25						
26	Total Amortization		(48,149)	(9,942)	2,878	(55,213)
27						
28	NET		100,802	($2,026)	$0	$98,776

TERASEN GAS INC..

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars (1)		Balance 12/31/2003 (2)	2004 Additions (3)	2004 Retirements (4)	Balance 12/31/2004 (5)
1	DSEP/GEAP	211-06	12,671	$0	$0	$12,671
2						
3	NGV Conversion Grants	211-07	0	0	0	$0
4						
5	NGV Station Grants	211-08	0	0	0	$0
6						
7	Furniture & Equipment	211-10	111	0	0	$111
8						
9	Software Tax Savings - Non-Infrastructure	211-11	13,272	548	(29)	$13,791
10	- Infrastructure/Custom	211-11	40,607	3,101	(2,828)	$40,880
11	Service Installation Fee	211-12	14,264	2,454	0	$16,718
12						
13	Other	211-00 to 05	61,964	2,837	(21)	$64,780
14						
15	TOTAL		142,889	8,940	(2,878)	148,951
16						
17						
18						
19	Amortization	211-15 to 22				
20						
21	- Software Tax Savings - Non-Infrastructure		(6,561)	(2,654)	29	($9,186)
22	- Infrastructure/Custom		(17,028)	(5,076)	2,828	($19,276)
23	- Other		(17,749)	(1,959)	21	($19,687)
24						
25						
26	Total Amortization		(41,338)	(9,689)	2,878	(48,149)
27						
28	NET		101,551	($749)	$0	$100,802

TERASEN GAS INC.

NET GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2004 TO 2005
($000)

Line No.	Particulars	Projection 2004	Forecast 2005	Reference
	(1)	(2)	(3)	(4)
1	Gas Plant in Service - December 31, Previous Year	$2,817,462	$2,922,348	
2				
3	Add: CPCNs on January 1, Beginning of the Year	14,075	53,749	
4				
5	Adjusted Opening Gas Plant in Service	2,831,538	2,976,097	
6				
7	Intangible Plant	837	837	- Tab 1, Page 6
8				
9	Less: Contribution in Aid of Construction	(142,889)	(148,951)	- Tab 3, Page 8
10				
11	Less: Accumulated Depreciation and Amortization	(509,202)	(561,718)	- Tab 3, Page 13
12				
13	Net Gas Plant in Service as at January 1,	$2,180,284	$2,266,265	- Tab 1, Page 6

The 2005 deferred charges and amortization (Section A, Tab 3, Pages 11 and 11.1) have been determined in accordance with the BCUC Decision dated February 4, 2003 on Terasen Gas' 2003 revenue requirements and the 2004-2007 PBR Plan Settlement Terms approved by Commission Order No. G-51-03.

The large accumulation in 2004 in the RSAM account is due to a combination of lower use rates than those approved in the 2004 Decision and warmer than normal weather. The amortization period continues to be 3 years.

With the implementation of the Commercial Commodity Unbundling Program the GCRA, effective April 1, 2004, was divided into a Commodity Cost Reconciliation Account (CCRA) and a Midstream Cost Reconciliation Account (MCRA).

CCRA is designated to capture and account for costs and recoveries associated with the baseload supply and for all of Terasen Gas' sales customers. MCRA is designated to capture and account for costs and recoveries associated with the remaining resources required to meet design peak day. The CCRA will capture the costs incurred by Terasen Gas to purchase its portion of the baseload gas requirements and the revenue collected by Terasen Gas through gas commodity rates. The MCRA will capture all the costs associated with the Midstream function and the revenue collected by Terasen Gas through midstream rates.

Future disposition of RSAM and CCRA/MCRA balances will be determined based on the net-of-tax balance in accordance with Commission Order No. G-34-03.

Under Section B, Tab 7, Terasen Gas addresses the need to adjust the cost of service for "Exogenous Factors" pursuant to the provisions of the 2004-2007 Settlement Agreement. Terasen proposes to defer the 2004 cost associated with Ontario Securities Commission (OSC) Certification Compliance and BCUC levies exceeding the amount provided for in 2004 rates and recover through rates in 2005. Terasen Gas also proposes to defer the forecast 2005 OSC Certification Compliance cost and recover fully in 2005.

The schedule of 2004 projected deferred charges and amortization is found in Section A, Tab 3, Pages 11.2 and 11.3.

TERASEN GAS INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Account	Projected Balance 12/312004	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2005	Mid-Year Average 2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	(2,837)	0	0	0	1,421	0	(1,416)	(2,127)
2										
3	NGV Conversion Grants	#17977	173	263	(91)	172	(53)	0	292	233
4										
5	2003 Revenue Requirement	#17989	207	0	0	0	(65)	0	142	175
6	2004-2007 Revenue Requirements	#17952	81	0	0	0	(20)	0	61	71
7										
8	Demand Side Management	#17916	912	1,500	(518)	982	(603)	0	1,291	1,102
9	DSM DRIA	#17961	(304)	0	0	0	159	0	(145)	(225)
10										
11	Property Tax Deferral	#17915	(1,298)	0	0	0	648	0	(650)	(974)
12										
13	M.C.R.A.	#17926	(32,771)	15,000	(5,175)	9,825	0	0	(22,946)	(27,859)
14	C.C.R.A.	#18137	6,054	48,000	(16,560)	31,440	0	0	37,494	21,774
15	C.C.R.A./M.C.R.A Interest	#17973	(819)	0	0	0	0	0	(819)	(819)
16										
17	RSAM	#17927	33,360	0	0	0	0	(11,120)	22,240	27,800
18	RSAM Interest	#17999	163	0	0	0	0	(54)	109	136
19										
20	Revelstoke Propane Cost	#27902	167	292	(101)	191	0	0	358	263
21										
22	Coastal Facilities									
23	- Relocation	#17951	341	0	0	0	(341)	0	0	171
24	- Extraordinary Plant Loss - Lochburn	#17998	82	0	0	0	(27)	0	55	69
25	- Fraser Valley NBV Amortization	#17996	206	0	0	0	(206)	0	0	103
26	- Noncapital Finance Costs	#17984	(6)	0	0	0	6	0	0	(3)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Account	Projected Balance 12/312004	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2005	Mid-Year Average 2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
27	Burner Tip Service	#17972	(1)	0	0	0	1	0	0	(1)
28										
32	Earnings Sharing Mechanism	#17982	0	0	0	0	0	0	0	0
33										
33	NGV Compression Equip. Recovery	#17992	1,065	0	0	0	(213)	0	852	959
34										
35	Overheads Change - Income Tax Refund	#17995	(416)	0	0	0	138	0	(278)	(347)
36	CIAOC Software Tax Savings/OH Change	#17995	(2,423)	0	0	0	808	0	(1,615)	(2,019)
37										
38	Other Post Employment Benefits	#17991/93	(12,825)	(6,623)	2,285	(4,338)	0	0	(17,163)	(14,994)
39										
40	Deferred 2000 SCP Cost of Service	#17997	190	0	0	0	(64)	0	126	158
41										
42	SCP Net Mitigation Revenues	#17912	(1,175)	733	(253)	480	520	0	(175)	(675)
43	SCP West to East Transmission	#17913	1,025	(46)	16	(30)	(347)	0	648	837
44	SCP PG&E Contract Cancellation	#17936	2,517	0	0	0	(503)	0	2,014	2,266
45										
46	CCT Deferral	#17924	(398)	0	0	0	133	0	(265)	(332)
47	CCT Assessment	#17929	921	1,100	(380)	720	(349)	0	1,292	1,107
48										
49	Pension Variance	#17946	203	0	0	0	(203)	0	0	102
50	Insurance Variance	#17947	(865)	0	0	0	865	0	0	(433)
51										
52	BCUC Levies		128	0	0	0	(128)	0	0	64
53	OSC Certification Compliance		284	421	(145)	276	(560)	0	0	142
54										
55	Total Deferred Charges for Rate Base		(8,059)	60,640	(20,922)	39,718	1,017	(11,174)	21,502	6,724

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Account	Balance 12/31/2003	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2004	Mid-Year Average 2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($4,287)	$34	(12)	$22	$1,428	$0	($2,837)	($3,562)
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	8	0	0	0	(8)	0	0	4
5										
6	NGV Conversion Grants	#17977	191	63	(22)	41	(59)	0	173	181
7										
8	2003 Revenue Requirement	#17989	272	0	0	0	(65)	0	207	240
9	2004-2007 Revenue Requirements	#17952	113	0	0	0	(32)	0	81	97
10										
11	Demand Side Management	#17916	1,512	455	(157)	298	(898)	0	912	1,212
12	DSM DRIA	#17961	(391)	0	0	0	87	0	(304)	(348)
13										
14	Property Tax Deferral	#17915	(1,419)	(640)	221	(419)	540	0	(1,298)	(1,359)
15										
16	M.C.R.A.	#17926	(12,714)	(31,607)	10,904	(20,703)	0	646	(32,771)	(22,743)
17	C.C.R.A.	#18137	0	9,243	(3,189)	6,054	0	0	6,054	3,027
18	C.C.R.A./M.C.R.A Interest	#17973	(422)	(606)	209	(397)	0	0	(819)	(621)
19										
20	RSAM	#17927	37,738	15,008	(5,178)	9,830	0	(14,208)	33,360	35,549
21	RSAM Interest	#17999	220	22	(8)	14	0	(71)	163	192
22										
23	Revelstoke Propane Cost	#27902	(10)	270	(93)	177	0	0	167	79
24										
25	B.C. Hydro Service Agreement Costs	#17963	471	0	0	0	(471)	0	0	236
26										
27	Coastal Facilities									
28	- Relocation	#17951	682	0	0	0	(341)	0	341	512
29	- Extraordinary Plant Loss - Lochburn	#17998	96	8	0	8	(22)	0	82	89
30	- Fraser Valley NBV Amortization	#17996	419	0	0	0	(213)	0	206	313
31	- Noncapital Finance Costs	#17984	362	0	0	0	(368)	0	(6)	178

TERASEN GAS INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Account	Balance 12/31/2003	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2004	Mid-Year Average 2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	ABC T Project Requirements Phase	#17918	30	0	0	0	(30)	0	0	15
33										
34	Burner Tip Service	#17972	(6)	0	0	0	5	0	(1)	(4)
35										
36	Earnings Sharing Mechanism	#17982	0	0	0	0	0	0	0	0
37										
38	NGV Compression Equip. Recovery	#17992	1,278	0	0	0	(213)	0	1,065	1,172
39										
40	2001 Rate Design	#17974	115	0	0	0	(115)	0	0	58
41										
42	Overheads Change - Income Tax Refund	#17995	(554)	0	0	0	138	0	(416)	(485)
43	CIAOC Software Tax Savings/OH Change	#17995	(3,231)	0	0	0	808	0	(2,423)	(2,827)
44										
45	Other Post Employment Benefits	#17991/93	(8,457)	(6,669)	2,301	(4,368)	0	0	(12,825)	(10,641)
46										
47	Deferred 2000 SCP Cost of Service	#17997	254	0	0	0	(64)	0	190	222
48										
49	SCP Net Mitigation Revenues	#17912	(2,455)	954	(329)	625	655	0	(1,175)	(1,815)
50	SCP West to East Transmission	#17913	1,388	(6)	2	(4)	(359)	0	1,025	1,207
51	SCP PG&E Contract Cancellation	#17936	889	2,485	(857)	1,628	0	0	2,517	1,703
52										
53	CCT Deferral	#17924	(531)	0	0	0	133	0	(398)	(465)
54	CCT Assessment	#17929	374	1,026	(354)	672	(125)	0	921	648
55										
56	Pension Variance	#17946	0	310	(107)	203	0	0	203	102
57	Insurance Variance	#17947	0	(1,320)	455	(865)	0	0	(865)	(433)
58										
59	BCUC Levies		0	196	(68)	128	0	0	128	64
60	OSC Certification Compliance		0	433	(149)	284	0	0	284	142
61	Total Deferred Charges for Rate Base		$11,935	($10,341)	$3,569	($6,772)	$411	($13,633)	($8,059)	$1,939

TERASEN GAS INC.

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005 2004 Rates	2005 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	($11,511)	($15,214)	($15,210)	(3,699)	
4						
5	Minimum Cash Balances/					
6	Customer Deposits	(3,813)	(2,629)	(2,629)	1,184	
7						
8	Less - Funds Available:					
9						
10	Reserve for Bad Debts	(775)	(2,700)	(2,700)	(1,925)	
11						
12	Withholdings From					
13	Employees	(2,700)	(2,344)	(2,344)	356	
14						
15	Subtotal	(18,799)	(22,887)	(22,883)	(4,084)	- Tab 1, Page 6
16						
17	**Other Working Capital Items**					
18	Inventories	4,054	6,900	6,900	2,846	
19	Transmission Line Pack Gas	2,993	3,260	3,260	267	
20	Gas in Storage	94,130	111,555	111,555	17,425	
21						
22						
23	Subtotal	101,177	121,715	121,715	20,538	- Tab 1, Page 6
24						
25	Total	$82,378	$98,828	$98,832	$16,454	

TERASEN GAS INC.

ACCUMULATED DEPRECIATION
FOR THE YEARS ENDING DECEMBER 31, 2004 - 2005
($000)

Line No.	Particulars	Projection 2004	Forecast 2005	Reference
	(1)	(2)	(3)	(4)
1	Balance, Beginning	$550,540	$609,868	- Tab 3, Page 13.3
2				
3	CIAOC Amortization Balance, Beginning	(41,338)	(48,149)	- Tab 3, Page 8
4				
5	Gas Plant Held for Future Use			
6	Balance, Beginning	0	0	
7				
8	Retirement Work in Progress	0	0	
9				
10	Utility Accumulated Depreciation			
11	Balance, Beginning	509,202	561,719	- Tab 3, Page 9
12				
13	Depreciation Provision			
14	Total Plant	87,231	90,736	- Tab 3, Page 13.3
15	Less - Gas Plant Held for Future Use	0	0	
16	Less Prior Year Adjustments			
17	Less - Amortization of Contributions in			
18	Aid of Construction	(9,689)	(9,942)	- Tab 3, Page 8
19				
20		77,542	80,794	
21				
22	Plant Retirements	(27,904)	(20,340)	- Tab 3, Page 13.3
23				
24	CIAOC Retirements	2,878	2,878	- Tab 3, Page 8
25				
26	Removal Costs	-	-	- Tab 3, Page 13.3
27				
28	Proceeds on Disposals	-	-	- Tab 3, Page 13.3
29				
30		(25,026)	(17,462)	
31				
32	Balance, Ending	$561,718	$625,051	- Tab 1, Page 6

TERASEN GAS INC.

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Account	Balance 12/31/2004	Annual Depreciation Rate %	Provision 2005 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2004	Accumulated 12/31/2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	46	47
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	333	340
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	45	46
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	26	27
7	402-00 Other Intangible Plant - Lease	772	Lease	0	0	0	0	0	115	115
8		1,771		10	0	0	0	0	565	575
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	430 Manufact'd Gas - Land	31	0.00%	0	0	0	0	0	0	0
22	432 Manufact'd Gas - Struct. & Improvements									
23	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
24	- Masonry Buildings	438	1.50%	7	0	0	0	0	70	77
25	433 Manufacturing Equipment	139	3.00%	4	0	0	0	0	29	33
26	434 Gas Holders - Manufacturing	358	2.00%	7	0	0	0	0	137	144
27	436 Compressor Equipment	53	3.00%	1	0	0	0	0	15	16
28	437 Measuring & Regulating	309	3.00%	9	0	0	0	0	105	114
29	440/441 Land in Fee Simple and Land Rights	927	0.00%	0	0	0	0	0	1	1
30	442-00 Structures and Improvements	5,455	4.00%	218	0	0	0	0	1,434	1,652
31	443-00 Gas Holders Storage	16,766	4.00%	671	0	0	0	0	6,503	7,174
32	449-00 Local Storage Equipment	16,734	4.00%	669	0	0	0	0	6,419	7,088
33		41,210		1,586	0	0	0	0	14,713	16,299

TERASEN GAS INC.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

				Provision					Accumulated	
Line No.	Account	Balance 12/31/2004	Annual Depreciation Rate %	2005 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	12/31/2004	12/31/2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$16	5.00%	$1	$0	$0	$0	$0	$15	$16
3	460-00 / 461-00 Land / Land Rights	46,920	0.00%	0	0	0	0	0	(1,035)	(1,035)
4	462-00 Structures and Improvements - Compressor Str	14,784	3.00%	444	0	0	0	0	3,090	3,534
5	463-00 Measuring & Regulating	4,276	3.00%	128	0	0	0	0	687	815
6	464-00 Other Structures - Frame Buildings	4,881	3.00%	146	0	0	0	0	512	658
7	465-00 Mains & Crossings	699,359	2.00%	13,987	0	(310)	0	0	121,705	135,382
8	465-00 Mains & Crossings - Byron Creek	885	5.00%	44	0	0	0	0	653	697
9	466-00 Compressor Equipment	103,073	3.00%	3,092	0	0	0	0	19,398	22,490
10	467-00 Measuring & Regulating	31,405	3.00%	942	0	0	0	0	2,525	3,467
11	467-10 Telemetering	5,628	10.00%	563	0	0	0	0	4,623	5,186
12	468-00 Communications Structures & Equip.	1,021	10.00%	102	0	0	0	0	111	213
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		912,248		19,449	0	(310)	0	0	152,284	171,423
15										
16	**DISTRIBUTION PLANT**									
17	470 Land	3,248	0.00%	0	0	0	0	0	34	34
18	471 Land Rights	678	0.00%	0	0	0	0	0	0	0
19	471 Land Rights - Byron Creek	1	0.00%	0	0	0	0	0	3	3
20	472-00 Structures & Improvements									
21	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
22	-Frame Buildings	7,027	3.00%	211	0	0	0	0	1,564	1,775
23	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
24	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
25	473-00 Services	541,726	2.00%	10,835	0	(3,074)	0	0	80,654	88,415
26	474-00 House Regulator & Meter Installation	137,837	3.57%	4,921	0	(458)	0	0	21,276	25,739
27	475-00 Mains	735,038	2.00%	14,701	0	(3,085)	0	0	172,446	184,062
28	476-00 Compressed Natural Gas									
29										
30	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
31	-All Other	575	6.67%	38	0	0	0	0	212	250
32	477-00 Measuring & Regulating	62,545	3.00%	1,876	0	(507)	0	0	6,841	8,210
33	477-10 Telemetering	5,019	10.00%	502	0	0	0	0	3,791	4,293
34	477-00 Measuring & Regulating - Byron Creek	195	5.00%	10	0	0	0	0	(67)	(57)
35	478 Meters	188,141	3.57%	6,717	0	(755)	0	0	32,967	38,929
36	479 Other Distribution Equipment	0	4.00%	0	0	0	0	0	0	0
37		1,682,032		39,811	0	(7,879)	0	0	319,723	351,655

TERASEN GAS INC.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Account	Balance 12/31/2004	Annual Depreciation Rate %	Provision 2005 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2004	Accumulated 12/31/2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	480 Land	20,936	0.00%	0	0	(5)	0	0	12	7
3	482-00 Structures & Improvements									
4	-Leasehold Alterations	$12,795	Term - Lease	$571	$0	$0	$0	$0	$12,851	$13,422
5	-Masonry Buildings	76,603	1.50%	1,149	0	(1,050)	0	0	1,309	1,408
6	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,390)	(3,253)
7	483-00 Office Furniture & Equipment									
8	-Furniture & Equipment	24,266	5.00%	1,213	0	(23)	0	0	9,524	10,714
9	-Computers - Hardware	24,241	20.00%	4,848	0	(3,293)	0	0	17,001	18,556
10										
11	-Computer Software - Non-Infrastructure	38,691	20.000%	7,738	0	0	0	0	27,498	35,236
12	-Computer Software - Infrastructure/Custom	92,044	12.50%	11,505	0	(6,809)	0	0	39,074	43,770
13										
14	484-00 Transportation Equipment	590	15.00%	89	0	(8)	0	0	2,555	2,636
15	485-00 Maintenance & Repair Equipment	366	5.00%	18	0	0	0	0	(328)	(310)
16	486-00 Tools & Work Equipment	27,456	5.00%	1,373	0	(184)	0	0	10,066	11,255
17	487-00 Equipment on Customers' Premises	1,230	5.00%	62	0	0	0	0	675	737
18	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
19	487-XX - VRA Compressor Installation Cost	583	33.33%	194	0	0	0	0	498	692
20	488-00 Communication - Structures & Equip.	10,668	5.00%	533	0	(779)	0	0	2,209	1,963
21	488-00 Communication - Radios	4,497	10.00%	450	0	0	0	0	3,029	3,479
22	489-00 Other General Equipment	2	5.00%	0	0	0	0	0	0	0
23		339,520		29,880	0	(12,151)	0	0	122,583	140,312
24										
25	**UNCLASSIFIED PLANT**									
26	499 Plant Suspense	153	0.00%	0	0	0	0	0	0	0
27										
28	TOTAL	$2,976,934		$90,736	$0	($20,340)	$0	$0	$609,868	$680,264

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2003	Accumulated 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	45	46
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	326	333
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	44	45
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	25	26
7	402-00 Other Intangible Plant - Lease	772	Lease Term	0	0	0	0	0	115	115
8		1,771		10	0	0	0	0	555	565
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	102-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	102-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	102-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	430 Manufact'd Gas - Land	31	0.00%	0	0	0	0	0	0	0
22	432 Manufact'd Gas - Struct. & Improvements									
23	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
24	- Masonry Buildings	438	1.50%	7	0	0	0	0	63	70
25	433 Manufacturing Equipment	139	3.00%	4	0	0	0	0	25	29
26	434 Gas Holders - Manufacturing	358	2.00%	7	0	0	0	0	130	137
27	436 Compressor Equipment	53	3.00%	1	0	0	0	0	14	15
28	437 Measuring & Regulating	309	3.00%	9	0	0	0	0	96	105
29	440/441 Land in Fee Simple and Land Rights	927	0.00%	0	0	0	0	0	1	1
30	442-00 Structures and Improvements	5,455	4.00%	218	0	0	0	0	1,216	1,434
31	443-00 Gas Holders Storage	16,376	4.00%	655	0	0	0	0	5,848	6,503
32	449-00 Local Storage Equipment	16,734	4.00%	669	0	0	0	0	5,750	6,419
33		40,820		1,570	0	0	0	0	13,143	14,713

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2003	Accumulated 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$16	5.00%	$1	$0	$0	$0	$0	$14	$15
3	460-00 / 461-00 Land / Land Rights	44,981	0.00%	0	0	0	0	0	(1,035)	(1,035)
4	462-00 Structures and Improvements - Compressor	14,393	3.00%	432	0	0	0	0	2,658	3,090
5	463-00 Measuring & Regulating	4,363	3.00%	131	0	(87)	0	0	643	687
6	464-00 Other Structures - Frame Buildings	4,881	3.00%	146	0	0	0	0	366	512
7	465-00 Mains & Crossings	693,065	2.00%	13,861	0	(683)	0	0	108,527	121,705
8	465-00 Mains & Crossings - Byron Creek	885	5.00%	44	0	0	0	0	609	653
9	466-00 Compressor Equipment	102,880	3.00%	3,086	0	0	0	0	16,312	19,398
10	467-00 Measuring & Regulating	28,166	3.00%	845	0	(1,950)	0	0	3,630	2,525
11	467-10 Telemetering	5,628	10.00%	563	0	0	0	0	4,060	4,623
12	468-00 Communications Structures & Equip.	355	10.00%	36	0	0	0	0	75	111
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		899,612		19,145	0	(2,720)	0	0	135,859	152,284
15										
16	**DISTRIBUTION PLANT**									
17	470 Land	3,249	0.00%	0	0	(1)	0	0	35	34
18	471 Land Rights	678	0.00%	0	0	0	0	0	0	0
19	471 Land Rights - Byron Creek	1	0.00%	0	0	0	0	0	3	3
20	472-00 Structures & Improvements									
21	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
22	-Frame Buildings	6,669	3.00%	200	0	(1)	0	0	1,365	1,564
23	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
24	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
25	473-00 Services	522,204	2.00%	10,444	0	(2,332)	0	0	72,542	80,654
26	474-00 House Regulator & Meter Installation	130,972	3.57%	4,676	0	(2,388)	0	0	18,988	21,276
27	475-00 Mains	706,906	2.00%	14,138	0	(2,729)	0	0	161,037	172,446
28	476-00 Compressed Natural Gas									
29										
30	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
31	-All Other	575	6.67%	38	0	0	0	0	174	212
32	477-00 Measuring & Regulating	53,516	3.00%	1,605	0	(328)	0	0	5,564	6,841
33	477-10 Telemetering	5,019	10.00%	502	0	0	0	0	3,289	3,791
34	477-00 Measuring & Regulating - Byron Creek	195	5.00%	10	0	0	0	0	(77)	(67)
35	478 Meters	174,566	3.57%	6,232	0	(1,393)	0	0	28,128	32,967
36	479 Other Distribution Equipment	0	4.00%	0	0	0	0	0	0	0
37		1,604,552		37,845	0	(9,172)	0	0	291,050	319,723

TERASEN GAS INC.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2003	Accumulated 12/31/2004
		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	GENERAL PLANT									
1	480-00 Land	20,921	0%	$0	$0	($5)	$0	$0	$17	$12
2	482-00 Structures & Improvements									
3	-Leasehold Alterations	$12,795	Term - Lease	$540	$0	$0	$0	$0	$12,311	$12,851
4	-Masonry Buildings	26,777	1.50%	402	0	(1,050)	0	0	1,957	1,309
5	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,527)	(3,390)
6	483-00 Office Furniture & Equipment									
7	-Furniture & Equipment	23,820	5.00%	1,191	0	(20)	0	0	8,353	9,524
8	-Computers - Hardware	24,696	20.00%	4,939	0	(6,459)	0	0	18,521	17,001
9										
10	-Computer Software - Non-Infrastructure	37,218	20.00%	7,444	0	0	0	0	20,054	27,498
11	-Computer Software - Infrastructure/Custom	90,705	12.50%	11,338	0	(7,014)	0	0	34,750	39,074
12										
13	484-00 Transportation Equipment	809	15.00%	121	0	(261)	0	0	2,695	2,555
14	485-00 Maintenance & Repair Equipment	370	5.00%	19	0	(4)	0	0	(343)	(328)
15	486-00 Tools & Work Equipment	25,763	5.00%	1,288	0	(222)	0	0	9,000	10,066
16	487-00 Equipment on Customers' Premises	1,230	5.00%	62	0	0	0	0	613	675
17	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
18	487-XX - VRA Compressor Installation Cost	583	33.33%	194	0	0	0	0	304	498
19	488-00 Communication - Structures & Equip.	10,727	5.00%	536	0	(977)	0	0	2,650	2,209
20	488-00 Communication - Radios	4,497	10.00%	450	0	0	0	0	2,579	3,029
21	489-00 Other General Equipment	2	5.00%	0	0	0	0	0	0	0
22		285,466		28,661	0	(16,012)	0	0	109,934	122,583
23										
24	**UNCLASSIFIED PLANT**									
25	499-00 Plant Suspense	153	0.00%	0	0	0	0	0	0	0
26										
27	TOTAL	$2,832,374		$87,231	$0	($27,904)	$0	$0	$550,541	$609,868

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2005 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-4 INDEX

This Section addresses the forecast of gas sales and transportation volumes for 2005. Included in this Section is a review of the energy forecast methodology, as well as factors influencing customer additions and use per customer. An outline of the residential, commercial and industrial margins and revenues over the forecast period is also provided.

The yearly projections and forecasts provided in this Section are the best current estimates. Customer accounts and the use per account used to derive revenues for 2005 reflect the best information available at the time of the Annual Review.

The forecast of industrial accounts and associated volumes are updated to reflect the latest Industrial Survey conducted during the summer of 2004. Similarly, revenue and margin forecasts reflect the most recently approved rates.

1. FORECAST METHODOLOGY

Consistent with previous years, the forecasting process is comprised of three main components:

- Customer additions forecast;
- Average Use per Residential and Commercial Account Forecast; and
- Industrial Forecast.

The residential and commercial energy forecast consisting of Rates 1, 2, 3, and 23 is driven by the respective account and use per customer forecasts, while the industrial energy forecast incorporates Rates 5, 7, 22, 25 and 27 and is based mainly on customer survey data. Seasonal (Rate 4) and Natural Gas Vehicle (Rate 6) account and demand growth is modelled from market information and historical trends.

The customer additions forecast reflects prevailing macroeconomic circumstances affecting residential and commercial customers. The forecast for industrial customers assumes no net change in the number of customers over the forecast period, except where written requests for change of service have been received by Terasen Gas.

Consistent with the methodology used in prior years, the average use per customer is estimated for Rates 1, 2, 3 and 23 and is multiplied by the corresponding forecast of customers in each respective class to derive energy by rate class. The large volume industrial and transportation customer throughput forecast continues to rely on historical data, sector analyses and customer-specific survey results.

Up-to-date tariff schedules and rates are then applied against the energy forecast to calculate the revenue forecast. The underlying assumptions and components of that forecast are discussed below.

2. UNDERLYING ASSUMPTIONS

Terasen Gas expects recent conservation efforts and trends to persist.

Although the forecast assumes a modest recovery in most sectors of the regional economy, possible economic inhibitors such as the softwood lumber dispute are assumed unresolved before the end of 2004. Primary considerations of the energy forecast are summarised below.

- Natural gas commodity prices continue to remain high relative to historical levels and experience some price volatility.
- Regional economic recovery with modest growth for the balance of 2004 and 2005.
- Energy efficiency improves with appliance renewal and continuing conservation efforts.
- The competitive positioning of gas relative to electricity experiences some improvement.
- Key industrial and transportation sectors experience limited growth, but with energy volumes offset by improved energy efficiency.

3. ECONOMIC OUTLOOK FOR BRITISH COLUMBIA

In its Balanced Budget 2004 announced in February 2004, the B.C. Ministry of Finance projected economic growth (real GDP) in British Columbia of 2.8 per cent in 2004 and 3.1 per cent in 2005. The unemployment rate is expected to decline from 8.1% experienced in 2003 to 7.9% in 2004 with the seasonally adjusted unemployment rate reported as of August 2004 at

7.7%. The outlook for 2005 is continued improvement in employment with a projected 7.7% unemployment rate.

Recent economic outlooks produced by the Conference Board of Canada and various financial banking institutions[1] are consistent with the Ministry of Finance's projections of an improving economy in the near term.

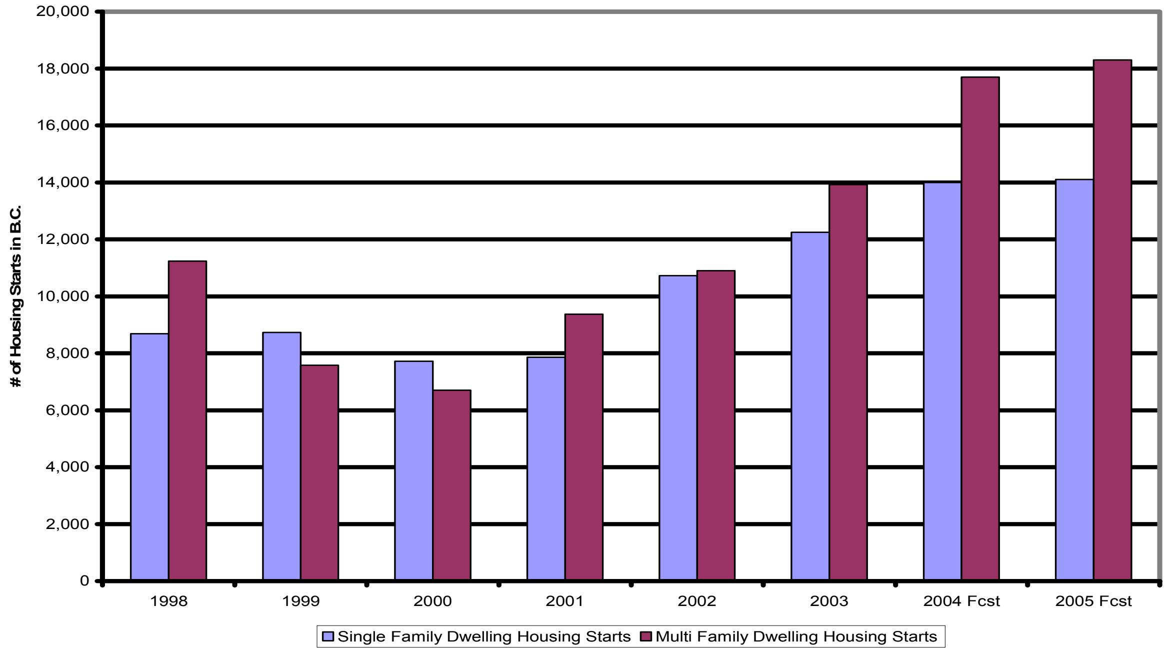
Housing Market

The housing market in BC has experienced strong gains since 2001; this trend is expected to continue. For 2004, the new housing market shows continued strength in new housing starts. According to the Canada Mortgage and Housing Corporation (CMHC)[2], employment growth and continued consumer optimism are driving demand for existing and new housing markets. To June 2004, single detached housing starts increased 18% year over year, from 5,190 for June 2003 to 6,133 starts. Multiple home starts experienced considerably more growth, from 5,113 for June 2003 to 8,840 starts year to date, representing a 73% increase year over year.

High consumer confidence, low interest rates, favourable migration, and an improving BC economy will continue to sustain a housing boom in BC over the next two years.

[1] BMO Financial Group – July 28, 2004 (GDP growth – 2004 2.7%, 2005 3.2%), Conference Board of Canada – July 15, 2004 (GDP Growth – 2004 3.0%, 2005 2.7%), RBC Financial Group – May 2004 (GDP growth – 2004 3.0%, 2005 3.5%).
[2] CMHC "Housing Now – Your Link to the Housing Market" – British Columbia August 2004 edition.

BC Housing Starts[3]



The latest CMHC housing starts forecast for B.C. published in August 2004 projects 31,700 housing starts for 2004 and 32,400 for 2005. The majority of new housing starts are expected to occur in the Greater Vancouver region. Demand for new multi-family homes are expected to remain strong in response to demand for affordable homes from first-time buyers and demand from investors.

Customer Additions Forecast

The customer addition forecast is derived from broad regional economic forecasts and end-use information. Inputs gathered through industrial associations, research institutes, government agencies and periodic surveys provide the basis for relating economic data to account growth.

To forecast residential account additions, actual household formation, estimated market share, and historical commodity price are statistically linked with actual account additions to model annual account growth on a service area basis. Household formation, market share and commodity price forecasts are then applied to obtain the expected number of additions adjusted for actual customer counts to date (August 2004). For the forecast produced in support of the

[3] CMHC.

2004 Annual Review, the BC Statistics 2004 Household Formation Forecast[4] is used as the primary predictor variable to estimate household formations by area over the forecast period, with the near-term forecast validated by current housing start and service request information.

The housing boom sparked by low mortgage rates and improving consumer confidence is continuing to add new customer services at rates somewhat higher than those anticipated in prior forecasts. Although mortgage rates are expected to slowly rise, a recent trend of households moving from other provinces to BC and a shift toward more full time employment in BC's urban centers is expected to maintain the current boom for the balance of this year and through 2005[5].

The table below provides a summary of the Residential and Commercial customer additions for the last 3 years, and a projection for 2004 and the 2005 forecast customer additions. It also shows year-to-year changes in housing starts and population growth.

TGI Customer Growth[1]

	2001 ACTUALS	2002 ACTUALS	2003 ACTUALS	2004 PROJECTED	2005 FORECAST
Residential	4,835	7,360	6,306	11,711	9,652
Commercial	16	(220)	(762)	(291)	501
Industrial & Transportation	906	(533)	2	(8)	(9)
Total Change	**5,757**	**6,607**	**5,546**	**11,412**	**10,144**
Year-Ending Customers	763,363	769,970	775,516	786,928	797,072
Housing Starts[2]	17,234	21,625	24,050	31,700	32,400
Population Growth[3]	0.8%	1.0%	1.4%	1.4%	1.2%

Notes

1. Includes Lower Mainland, Inland, Columbia, & Revelstoke service regions only.

3. Housing Stats forecast for 2004 from CMHC, October 2004.

3. Population Growth Forecast from 2004 BC Stats Provincial Population Forecast - BC Ministry of Finance & Corporate Relations.

[4] Updated January 2004.

[5] CMHC Release, October 8, 2004.

The 11,413 customers projected for 2004 includes an estimated 1500 customers that were attached in 2003, but were not counted until January 2004 because of the timing of 2003 year-end processing. Adjusting the 2004 projection for these 1500 customers suggests a slight increase in the number of customers in 2005. This increase is consistent with the current housing starts forecast and general economic outlook described earlier.

4. USE PER CUSTOMER FORECAST

Individual use per account projections were developed for each service area and rate class by considering the following factors:

- The most recent historical normalized use per account;
- Customer migration between rates;
- Forecast use for new customer additions;
- Appliance conversion or replacement effects where applicable; and
- The estimated impact of demand side management programs over the forecast period.

In response to changes in customer lifestyle and the provincial demographic profile, Terasen Gas expects the proportionate share of multiple housing to increase over the next several years. Homeowner preference shifts toward apartment-style condominiums and townhouses, will put some further downward pressure on residential usage per account. Other factors causing downward pressure on use-rates include space heating efficiency, improved home insulation and setback thermostats.

With gas prices stabilizing somewhat in 2004, normalized residential use rates are expected to remain at 2003 levels. The demand response to rising prices is tapering off, and as a result consumption is recovering (enough to offset gains in technology and end-use changes). Projected use rates for 2004 are based on forecast use rates, adjusted for actual normalized use to the end of August.

For commercial rate classes, use per account increased during 2004. The average use-rate for Rate 2 customers is expected to increase from 303.6 GJs in 2003 to an expected 305.3 GJs in 2004. Similarly the Rate 3 and 23 customer use-rates are expected to increase from levels experienced in 2003 to 3488.6 GJ and 4975.3 GJ respectively in 2004. Projected use rates for

2004 are based on forecast use rates, adjusted for actual normalized use to the end of August. Commercial unbundling, offered to Rate 2 & 3 customers beginning November 2004, is not expected at this time to have an impact on use rates.

The competitive price perception of natural gas has eroded in recent years, notwithstanding that gas continues to be the most cost effective energy alternative for many applications. With electricity rate increases expected in 2005, the forecast assumes that electricity rate increases will help preserve the relative competitiveness of natural gas as a heating energy source over the next few years.

A summary of historic customer usage and the forecast use per account values are set out below. The forecast use per account values in the table below were used to develop the revenue forecasts in this Annual Review. For comparison purposes, use rates approved to set 2004 rates are also included in the table below.

Historic & Forecast Annual Use Rates - Rates 1, 2, 3, & 23 (GJs)

	2001 NORMAL	2002 NORMAL	2003 NORMAL	2004 APPROVED	2004 PROJECTED	2005 FORECAST
Rate 1	100.5	105.6	103.1	104.7	103.1	103.3
Rate 2	305.4	301.8	303.6	300.1	305.3	317.1
Rate 3	3,332.1	3,378.1	3,292.0	3,342.4	3,488.6	3,426.0
Rate 23	5,802.4	5,281.1	4,883.4	5,301.2	4,981.8	4,975.3

5. ENERGY FORECAST

a. Residential/Commercial

The residential and commercial energy forecast is calculated by multiplying the estimated energy use per account by the total number of customers including customer additions. From 2004, residential consumption is expected to rise marginally from 72.4 to 73.6 PJs while commercial use is forecast to increase from 44.5 to 45.4 PJs. The forecast for each year is provided in the summary table at the end of this section.

b. Industrial

As with previous years, the primary source of information for the industrial energy forecast is a customer survey, which was conducted over the summer of 2004. Surveys were faxed or mailed to each customer in rate schedules 5, 7, 22, 25 and 27. Customers were asked to what extent they expect their firm's natural gas consumption to change from the previous year, and then to estimate their consumption over the forecast period. The industrial energy forecast was then updated to include these demand estimates and other pertinent feedback

A total of 409 surveys were completed, representing a response rate of 35% by number of accounts and 59% by forecast volume. Surveys were gathered from customers across every service region, rate class, and industry.

Industrial energy consumption (excluding Burrard Thermal and Terasen Gas (Vancouver Island) to decrease marginally from 58.8 PJs in 2003 to 57.8 PJs in 2004. Overall, industrial load remains relatively stable, despite higher natural gas prices and a strengthening Canadian dollar.

The following table sets out the energy forecast by Residential, Commercial, Firm Sales, and Industrial rate classes.

Energy Forecast (PJs per annum)

	2001 NORMAL	2002 NORMAL	2003 NORMAL	2004 PROJECTED	2005 FORECAST
Residential[1]	68.4	72.6	72.6	72.4	73.6
Commercial[2]	43.9	44.3	45.3	44.5	45.4
Firm Sales[3]	8.9	6.9	6.1	5.4	5.3
Industrial[4]	55.6	59.4	58.8	57.7	57.6
Total	176.8	183.2	182.8	180.0	181.9

Notes

1. Rate 1.
2. Rates 2, 3, & 23.
3. Rates 4, 5, & 6.
4. Rates 7, 22, 25, & 27; Burrard Thermal & TGVI are excluded.

6. REVENUE FORECAST

Revenue forecasts for each customer class are developed from the total energy forecasts and the applicable rates. The revenue forecast below does not include amounts for Terasen Gas (Vancouver Island) and B.C. Hydro for Burrard Thermal.

The table below summarizes the 2004 Projection and 2005 Revenue Forecast by market segment and provides data from 2001-2003 for comparison purposes. Revenues increased substantially in 2001 due to the increases in the cost of natural gas; similarly Terasen Gas is forecasting an increase in total 2004 and 2005 revenues relative to 2002.

Revenue Forecast ($ millions per annum)

	2001 NORMAL	2002 NORMAL	2003 NORMAL	2004 PROJECTED	2005 FORECAST
Residential[1]	780.3	702.3	784.3	818.6	851.7
Commercial[2]	429.4	360.7	411.2	415.8	431.0
Firm Sales[3]	79.8	51.3	51.8	48.8	49.1
Industrial[4]	41.5	44.7	44.7	46.9	47.4
Total	1,331.0	1,159.0	1,292.0	1,330.1	1,379.2

Notes

1. Rate 1.
2. Rates 2, 3, & 23.
3. Rates 4, 5, & 6.
4. Rates 7, 22, 25, & 27; Burrard Thermal & TGVI are excluded.

7. MARGIN FORECAST

In 2004 and 2005, total margin is expected to change only modestly with the forecast incorporating approved rate increases and forecast customer growth. The table below sets out the forecast between Residential, Commercial, and Industrial Customers.

Margin Forecast ($ millions per annum)

	2001 NORMAL	2002 NORMAL	2003 NORMAL	2004 PROJECTED	2005 FORECAST
Residential[1]	250.8	264.0	273.2	285.2	289.8
Commercial[2]	112.2	113.7	118.8	121.8	123.9
Firm Sales[3]	14.1	12.3	10.5	11.1	10.9
Industrial[4]	38.3	43.9	43.5	46.0	46.3
Total	415.4	433.9	446.0	464.1	470.9

Notes

1. Rate 1.
2. Rates 2, 3, & 23.
3. Rates 4, 5, & 6.
4. Rates 7, 22, 25, & 27; Burrard Thermal & TGVI are excluded.

8. SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUES

SCP Third Party firm revenues will increase effective November 1, 2004 for a new contract replacing the canceled PG&E Energy Trading contract. For 2005, SCP Third Party firm revenues are forecast to be $10.9 million. This revenue forecast reflects the anticipated cancellation of the BC Hydro contract at the end of October 2005 and assumes that a replacement customer will be found to offset this loss starting November 2005.

Additional SCP mitigation revenue margin remains forecast at $1.0 million per year.

Variances from forecast in SCP Third Party revenues continue to be subject to deferral treatment as set out in the 2004–2007 Negotiated Settlement document.

9. MISCELLANEOUS REVENUE

Revenue from service work remains at $85 for customer additions and $25 for account transfers. Late Payment Charges are calculated using the O&M formula methodology as set out in the 2004–2007 Negotiated Settlement document. Annual NSF cheques are estimated at approximately 1% of the beginning of year account base at a rate of $20 per cheque.

Other miscellaneous revenue is estimated at approximately $1.2M and most of it is from NRB recoveries.

10. BURRARD THERMAL REVENUE

Various Burrard Thermal agreements generate approximately $9.9 million in revenues annually. The transportation charge is fixed and independent of energy consumption.

11. TERASEN GAS (VANCOUVER ISLAND) REVENUE

Revenue from wheeling demand charges and odorant cost recovery remains at approximately $4.1 million per year.

12. SUMMARY

The updated 2004 Year-End Forecast for 2004 reflects the best currently available information, and incorporates the following changes since the 2003 Year-End Forecast was completed:

1. Revenues adjusted to reflect current rates including all approved 2004 permanent delivery rates and gas cost increases;
2. Customer counts adjusted to reflect actual results to August 2004;
3. SCP Third Party revenues adjusted to reflect the revenue change from the PG&E contract cancellation and the replacement contract.; and
4. Use per account for Rates 1, 2, 3, and 23 is adjusted for actual normalized use to August 2004.

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2005

Line No.	Particulars	2004 Approved	2005 Terajoules Core and Non-Core	2005 Terajoules Bypass and Special Rates	2005 Terajoules Total	Change	Reference
	(1)	(2)	(5)	(6)	(7)	(5)	(6)
1	SALES						
2	Schedule 1 - Residential	73,250.9	73,587.7	0.0	73,587.7	337	
3	Schedule 2 - Small Commercial	21,289.4	22,448.0	0.0	22,448.0	1,159	
4	Schedule 3 - Large Commercial	18,596.0	17,879.4	0.0	17,879.4	(717)	
5							
6	Total Schedules 1, 2 and 3	113,136.3	113,915.1	0.0	113,915.1	778.8	
7							
8	Schedule 4 - Seasonal Service	234.4	179.5	0.0	179.5	(55)	
9	Schedule 5 - General Firm Service	6,404.5	4,806.4	0.0	4,806.4	(1,598)	
10							
11	Industrials						
12	Schedule 7 - Interruptible	121.5	73.7	0.0	73.7	(48)	
13							
14	Schedule 10	0.0	0.0	0.0	0.0	0	
15							
16	Total Industrials	121.5	73.7	0.0	73.7	(47.8)	
17							
18	Schedule 6 - N G V Fuel - Stations	268.5	327.3	0.0	327.3	59	
19							
20	Total Sales	120,165.2	119,302.0	0.0	119,302.0	(863.2)	- Tab 1, Page 7
21							
22	TRANSPORTATION SERVICE						
23	Schedule 22 - Firm Service	52,857.5	10,073.9	15,388.4	25,462.3	(27,395)	
24	- Interruptible Service	15,798.5	14,662.6	0.0	14,662.6	(1,136)	
25	Schedule 23 - Large Commercial	4,208.7	5,037.6	0.0	5,037.6	829	
26	Schedule 25 - Firm Service	12,326.4	12,409.8	2,103.4	14,513.2	2,187	
27	Schedule 27 - Interruptible	6,566.8	5,783.5	0.0	5,783.5	(783)	
28	Terasen Gas (Vancouver Island)	39,357.3	0.0	40,128.1	40,128.1	771	
29	Columbia Service Area - Byron Creek	158.7	0.0	97.0	97.0	(62)	
30							
31	Total Transportation Service	131,273.9	47,967.4	57,716.9	105,684.3	(25,589.6)	- Tab 1, Page 7
32							
33	TOTAL SALES AND TRANSPORTATION SERVICE	251,439.1	167,269.4	57,716.9	224,986.3	(26,452.8)	- Tab 1, Page 7

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005 Gas Sales Revenue At 2004 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(5)	(6)	(7)	(6)	(7)
1	SALES						
2	Schedule 1 - Residential	$851,826	$851,647	$0	$851,647	(179)	
3	Schedule 2 - Small Commercial	232,703	243,131	0	243,131	10,428	
4	Schedule 3 - Large Commercial	184,824	175,812	0	175,812	(9,012)	
5							
6	Total Schedules 1, 2 and 3	1,269,353	1,270,590	0	1,270,590	1,237	
7							
8	Schedule 4 - Seasonal Service	2,117	1,643	0	1,643	(474)	
9	Schedule 5 - General Firm Service	59,266	44,139	0	44,139	(15,127)	
10		61,383	45,782	0	45,782	(15,601)	
11	Industrials						
12	Schedule 7 - Interruptible	1,057	647	0	647	(410)	
13							
14	Schedule 10	0	0	0	0	0	
15							
16							
17	Total Industrials	1,057	647	0	647	(410)	
18							
19	Schedule 6 - N G V Fuel - Stations	2,755	3,307	0	3,307	552	
20							
21	Total Sales	1,334,548	1,320,326	0	1,320,326	(14,222)	- Tab 1, Page 7
22							
23	TRANSPORTATION SERVICE						
24	Schedule 22 - Firm Service	19,647	7,564	11,894	19,458	(189)	
25	- Interruptible Service	10,508	10,007	0	10,007	(501)	
26	Schedule 23 - Large Commercial	10,014	12,092	0	12,092	2,078	
27	Schedule 25 - Firm Service	17,770	20,147	836	20,983	3,213	
28	Schedule 27 - Interruptible	6,964	6,133	0	6,133	(831)	
29	Terasen Gas (Vancouver Island)	0	0	0	0	0	
30	Columbia Service Area - Byron Creek	0	0	38	38	38	
31							
32	Total Transportation Service	64,903	55,943	12,768	68,711	3,808	- Tab 1, Page 7
33							
34	TOTAL SALES AND TRANSPORTATION SERVICE	$1,399,451	$1,376,269	$12,768	$1,389,037	($10,414)	- Tab 1, Page 7

COST OF GAS BY RATE SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2005

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000)	Total Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CORE AND NON-CORE										
2	Core and Non-Core Sales										
3	Schedule 1 - Residential	54,677.5	$7.6540	$418,502	17,095.9	$7.5680	$129,381	1,814.3	$7.6830	$13,939	$561,822
4	Schedule 2 - Small Commercial	16,201.2	7.7420	125,430	5,584.4	7.6710	42,838	662.4	7.7690	5,146	173,414
5	Schedule 3 - Large Commercial	14,513.7	7.4750	108,490	3,114.3	7.4463	23,190	251.4	7.5100	1,888	133,568
6	Schedules 1, 2 and 3	85,392.4		652,422	25,794.6		195,409	2,728.1		20,973	868,804
7											
8	Schedule 4 - Seasonal	103.4	7.2244	747	76.1	7.1485	544.0	0.0	7.2720	0	1,291
9	Schedule 5 - General Firm	3,902.1	7.2290	28,208	852.0	7.1450	6,088	52.3	7.2720	380	34,676
10											
11	Industrial										
12	Interruptible - Schedule 7	56.9	7.2232	411	16.8	7.1429	120	0.0	0.0000	0	531
13	- Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
14	Total Industrials	56.9		411	16.8		120	0.0		0	531
15											
16	N G V Fuel - Stations - Schedule 6	310.4	6.9350	2,153	16.9	6.8700	116	0.0	6.8700	0	2,269
17											
18	Total NGV	310.4		2,153	16.9		116	0.0		0	2,269
19											
20	Total Core and Non-Core Sales	89,765.2		683,941	26,756.4		202,277	2,780.4		21,353	907,571
21											
22	Core and Non-Core Transportation Service										
23	Schedule 22 - Firm Service	0.0	0.0312	-	7,529.1	(0.0250)	(188)	2,544.8	0.1061	270	82
24											
25	- Interruptible Service	13,775.3	0.0312	429	628.0	(0.0250)	(16)	259.3	0.1061	28	441
26											
27	Schedule 23 - Large Commercial	4,255.2	0.0312	133	760.3	(0.0250)	(19)	22.1	0.1061	2	116
28	Schedule 25 - Firm Service	8,144.3	0.0312	254	3,857.2	(0.0250)	(96)	408.3	0.1061	43	201
29	Schedule 27 - Interruptible Service	5,209.4	0.0312	163	574.1	(0.0250)	(14)	0.0	0.1061	0	149
30	Total Core and Non-Core T-Service	31,384.2		979	13,348.7		(333)	3,234.5		343	989
31											
32											
33	Total Core and Non-Core Sales and										
34	Transportation Service										
35	Cost of Gas Sold	121,149.4		$684,920	40,105.1		$201,944	6,014.9		$21,696	$908,560

COST OF GAS BY RATE SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2005

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000)	Total Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	BYPASS AND SPECIAL RATES										
2	Bypass and Special Rates Sales										
3	Schedule 4 - Seasonal	0.0	$0.0000	$0	0.0	$0.0000	$0	0.0	$0.0000	$0	$0
4											
5	Large Industrial										
6	Interruptible - Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
7											
8											
9	Total Large Industrial	0.0		0.0	0.0		0.0	0.0		0.0	0
10	Total Bypass and Spec. Rates Sales	0.0		0.0	0.0		0.0	0.0		0.0	0
11											
12	Bypass and Special Rates Transportation Service										
13	Schedule 22 - Firm Service	0.0	0.0312	0	12,064.4	(0.0250)	(300)	324.0	0.1061	34	(266)
14											
15	- Interruptible Service	0.0	0.0312	0	0.0	(0.0250)	-	0.0	0.1061	0	0
16											
17	- Burrard Thermal - Firm	3,000.0	0.0156	47	0.0		0	0.0		0	47
18	Schedule 23 - Large Commercial	0.0	0.0312	0	0.0	(0.0250)	0	0.0	0.1061	0	0
19	Schedule 25 - Firm Service	0.0	0.0312	0	2,103.4	(0.0250)	(53)	0.0	0.1061	0	(53)
20	Schedule 27 - Interruptible Service	0.0	0.0312	0	0.0	(0.0250)	0	0.0	0.1061	0	0
21	Byron Creek	0.0	0.0000	0	0.0	0.0000	0	97.0	0.1061	10	10
22	Terasen Gas (Vancouver Island)	40,128.1	0.0156	626							626
23	Total Bypass and Spec. Rates T-Svc	43,128.1		673	14,167.8		(353)	421.0		44	364
24											
25											
26	Total Bypass and Special Rates Sales and										
27	Transportation Service										
28	Cost of Gas Sold	43,128.1		673	14,167.8		(353)	421.0		44	364
29											
30	Total Sales and Transportation										
31	Transportation Service										
32	Cost of Gas Sold	164,277.5		$685,593	54,272.9		$201,591	6,435.9		$21,740	$908,924

REVENUE UNDER PROPOSED 2004 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Terajoules	Revenue -- At 2004 Rates -- Average $/GJ	Revenue -- At 2004 Rates -- Revenue ($000)	Gross Margin -- At 2004 Rates -- Average $/GJ	Gross Margin -- At 2004 Rates -- Revenue ($000)	Increase / (Decrease) -0.2247% $/GJ	Increase / (Decrease) of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CAPTIVE										
2	Captive Sales										
3	Schedule 1 - Residential	73,587.7	$11.573	$851,647	$3.9385	$289,825	($0.0089)	($652)	712,205	$11.564	$850,995
4	Schedule 2 - Small Commercial	22,448.0	10.831	243,131	3.1057	69,717	(0.0070)	(157)	70,752	10.824	242,974
5	Schedule 3 - Large Commercial	17,879.4	9.833	175,812	2.3627	42,244	(0.0053)	(94)	5,218	9.828	175,718
6											
7	Total Schedules 1 , 2 and 3	113,915.1		1,270,590		401,786		(903)			1,269,687
8											
9											
10	Schedule 4 - Seasonal Service	179.5	9.153	1,643	1.9610	352	0.0000	0	21	9.153	1,643
11	Schedule 5 - General Firm Service	4,806.4	9.183	44,139	1.9688	9,463	(0.0044)	(21)	437	9.179	44,118
12											
13	Industrials										
14	Schedule 7 - Interruptible	73.7	8.779	647	1.5739	116	0.0000	0	5	8.779	647
15											
16	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
17											
18	Total Industrials	73.7		647		116		-			647
19											
20											
21	Schedule 6 - N G V Fuel - Stations	327.3	10.104	3,307	3.1714	1,038	(0.0061)	(2)	42	10.098	3,305
22	- VRA's	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
23											
24	Total Captive Sales	119,302.0		1,320,326		412,755		(926)	788,680		1,319,400
25											
26	Captive Transportation Service										
27	Schedule 22 - Firm Service	10,073.9	0.751	7,564	0.7427	7,482	(0.0018)	(18)	18	0.749	7,546
28	- Interruptible Service	14,662.6	0.682	10,007	0.6523	9,565	(0.0015)	(22)	27	0.681	9,985
29	Schedule 23 - Large Commercial	5,037.6	2.400	12,092	2.3773	11,976	(0.0054)	(27)	1,013	2.395	12,065
30	Schedule 25 - Firm Service	12,409.8	1.623	20,147	1.6073	19,946	(0.0036)	(45)	529	1.619	20,102
31	Schedule 27 - Interruptible Service	5,783.5	1.060	6,133	1.0347	5,984	(0.0022)	(13)	98	1.058	6,120
32											
33	Total Captive Transportation Service	47,967.4		55,943		54,953		(125)	1,685		55,818
34											
35											
36	Total Captive Sales and Transportation Service	167,269.4		$1,376,269		$467,708		($1,051)	790,365		$1,375,218

TERASEN GAS INC.

REVENUE UNDER PROPOSED 2004 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

			Revenue -- At 2004 Rates --		Gross Margin -- At 2004 Rates --		Increase / (Decrease) -0.22%	of Margin	Average	Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Revenue ($000)	$/GJ	Revenue ($000)	Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Bypass and Special Rates										
2											
3	Bypass and Special Rates - Sales										
4	Residential - Option A	0.0	$0.000	$0	$0.0000	$0	$0.000	$0	0	$0.000	$0
5	Schedule 4 - Seasonal Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
6	Schedule 5 - General Firm Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
9											
10	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
11											
12	Total Large Industrial	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.000	0	0.0000	0		0	0	0.000	0
15	- VRA's	0.0	0.000	0	0.0000	0		0	0	0.000	0
16											
17	Total Non-Captive Sales	0.0		0		0		0	0		0
18											
19	Non-Captive Transportation Service										
20	Schedule 22 - Firm Service	12,388.4	0.160	1,987	0.1819	2,254	0	0	1	0.160	1,987
21	Schedule 22 - Interruptible	0.0	0.000	0	0.0000	0	0	0	9	0.000	0
22	Schedule 25 - Interruptible	2,103.4	0.397	836	0.4226	889	0	0	7	0.397	836
23	Columbia - Byron Creek	97.0	0.392	38	0.2887	28	0	0	1	0.392	38
24	Burrard Transportation - Firm	3,000.0	3.302	9,907	3.2867	9,860	0	0	1	3.302	9,907
25	Terasen Gas (Vancouver Island)	40,128.1	0.102	4,094	0.0864	3,468	0	0	1	0.102	4,094
26	SCP Third Party Revenue			11,897		11,897					11,897
27	Total Non-Captive Transportation Service	57,716.9		28,759		28,396		0	20		28,759
28											
29	Total Non-Captive Sales and										
30	Transportation Service	57,716.9		28,759		28,396		0	20		28,759
31											
32	TOTAL CAPTIVE AND NON-CAPTIVE SALES AND										
33	TRANSPORTATION SERVICE	224,986.3		$1,405,028		$496,104		($1,051)	790,385		$1,403,977

OTHER OPERATING REVENUE
FOR THE YEARS ENDED DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2	Late Payment Charge	$4,877	$5,003	$126	
3	Connection Charge and NSF Cheque	4,001	4,192	191	
4	Total Other Utility Revenue	8,878	9,195	317	
5	**Miscellaneous Revenue**				
6	TGVI Wheeling Charge	4,025	4,094	69	
7	SCP Third Party Revenue	8,820	11,897	3,077	
8	Other	910	1,189	279	
9	Total Miscellaneious	13,755	17,180	3,425	
10	**Total Other Operating Revenue**	$22,633	$26,375	$3,742	- Tab 1, Page 7

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2005 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-5 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
2005 OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2005

In accordance with the PBR settlement, the 2005 operating and maintenance costs are determined on 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 50% of CPI (BC). The forecast of 2005 inflation based on CPI (BC) is 2.00% as discussed under Section A, Tab 2.

For the purpose of 2005 rates setting, 2004 O&M formula based O&M expense has been adjusted based on updated 2004 customer accounts. Per Commission Order No. G-51-03, there is no true-up on CPI. Also, there is no customer count-related true-up for 2004 overhead capitalization. The detail calculation of adjusted 2004 O&M base is shown on Page 2 of the same Tab.

For 2005, the annual operating and maintenance expenses are based on the following formula:

Gross O&M = 2004 Adjusted O&M X [(1 + customer growth) X (1 + CPI – adjustment factor)] + Pension & Insurance Variance

Gross 2005 O&M	$ 190.586 million
Capitalized Overhead	(26.335) million
Fort Nelson O&M and Vehicle Lease	(2.522) million
Net 2005 O&M	$ 161,729 million

Details in support of the above calculation can be found on Page 2 of this Tab.

As per Commission Order No. G-51-03, variances between PBR formula based pension and insurance costs and cost of service based have also been included as 2005 O&M expenses. Based on the calculation shown on Page 3 of this tab, incremental of $11,000 is added to O&M expenses.

Consistent with the 2003 Decision and the terms of the Settlement, the Company has kept the overheads capitalized rate at 16% for the 2005 year.

TERASEN GAS INC.

FORMULA CALCULATION OF
OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2005
($000) - Except where noted

Line No.	Description		2003 Decision Adjusted for TPIP	Change	Approved 2004	Customer Base Adjustment 2003	Change	Adjusted Base 2004	Change	2005
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Average Number of Customers - Forecast		770,368	7,411	777,779				10,887	790,385
2	Percentage Growth in Average Customers			0.96%					1.40%	
3										
4	Average Number of Customers - True up (Actual/Projection)					770,624	8,874	779,498		
5	Percentage Growth in Average Customers						1.15%			
6										
7	Annual Inflation Rate - CPI			1.70%			1.70%		2.00%	
8	Adjustment Factor			0.85%			0.85%		1.00%	
9										
10	Total Gross O & M Expense before TPIP		$176,915							
11	TPIP		5,505							
12	Total Gross O & M Expense		182,420	$3,320	$185,740		$3,669	$186,089	$4,486	190,575
13	Pension & Insurance Variance			2,144	2,144		2,144	2,144	(2,134)	11
14	Adjusted Total Gross O&M Expense				187,884			188,233		190,586
15										
16	Less: Adjustments for Overhead Capitalized Purpose									
17	Fort Nelson	($581)								
18	Vehicle Lease	(1,833)								
19	DRIA	(1,652)								
20	OPEB	(6,329)								
21	Capital-related Portion - CustomerWorks	(8,978)								
22	Total Items Not Subject to Overheads	($19,373)	(19,373)		(19,726)			(19,763)		(20,239)
23	Less: TPIP Not Subject to Overhead		(5,505)		(5,605)			(5,616)		(5,751)
24	Total O&M Subject to Capitalized Overhead		157,542	5,011	162,553		5,312	162,854	1,741	164,596
25										
26	Capitalized Overhead at 16%		25,207		26,009			26,009		26,335
27	Gross O&M Less Capitalized Overhead		157,213	4,662	161,875		5,011	162,224	2,026	164,251
28										
29	Less: Fort Nelson		(581)	(11)	(592)		(12)	(593)	(14)	(607)
30	Vehicle Lease		(1,833)	(33)	(1,866)		(37)	(1,870)	(45)	(1,915)
31	Total Utility O&M		$154,799	$4,618	$159,417		$4,962	$159,761	$1,967	$161,729

TERASEN GAS INC.

FORMULA CALCULATION OF O & M EPXENSE
PENSION AND INSURANCE VARIANCE
FOR THE YEAR ENDING DECEMBER 31, 2005
($000) - Except where noted

Line No.	Particulars	Decision 2003	Change	Approved 2004	Adjusted Base 2004	Change	2005	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Based**							
2	Pension	$5,543	$101	$5,644	$5,654	$147	$5,791	
3	Insurance	3,661	67	3,728	$3,735	97	3,825	
4	Total	9,204	168	9,372	9,389	244	9,615	
5								
6	**Cost of Service Based**							
7	Pension			5,616			4,626	
8	Insurance			5,900			5,000	
9	Total			11,516			9,626	
10								
11	**Pension & Insurance Variance**							
12	Pension			(28)			(1,165)	
13	Insurance			2,172			1,175	
14	**Total Pension and Insurance Variance**			$2,144			$11	- Tab 5, Page 2

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT REVISED FORECASTS AND PROJECTIONS FOR 2005 REVENUE REQUIREMENTS AND OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-6 INDEX

1. PROPERTY TAX EXPENSE

Under the PBR, property taxes will be forecast each year for the Annual Review process. The Property Tax deferral account will collect all variances from the forecast amount included in rates.

The projected 2004 property tax is lower than previous forecast by $640,000. Under the terms of the Negotiated Settlement, forecast variances are afforded deferral treatment. For 2005, the forecast property tax is $39,573,000. Details in support of this amount can be found on Page 4 of this tab.

Property taxes are levied against the Company by Provincial, Municipal and other local governments.

1% Tax

The 1% tax in lieu of general municipal taxes ("1% tax") is calculated based on the amount of revenues collected within municipal boundaries multiplied by 1% (1.25% for the City of Vancouver). Payments of the 1% tax to municipalities are lagged relative to increases and decreases in revenues due to provisions in the applicable legislation and agreements. 2005 Budget payments are based on actual 2003 revenues, except for Vancouver which will be based on 2004 revenues. It is estimated that Vancouver Revenues will increase by 1%.

General, School and Other

Property taxes include general, school and other property taxes as well as Oil and Gas Commission fees. Assessed values for assets other than transmission pipe and land are estimated using 2004 actual assessments and market adjustments of 0.5 to 1%. The only exception to this is the 2005 transmission pipeline commissioner rates which on average are not expected to increase in 2005. This will be the second year of a three year phase in period; however, an error was discovered by Terasen Gas in the legislated rates in 2004. The most significant error (6” pipe) was corrected in 2004 with an agreement to correct the remaining rates in 2005 ensuring the net effect over the two years would be the same, and the actual overall increase is still estimated at 13.5% once the 3 year phase-in is completed. The change was the result of a review undertaken by BC Assessment on the legislated pipeline rates, and consultation with various pipeline companies including Terasen Gas Inc. Mill rates for general property taxes are forecast to increase by .5% to .75% annually and are set separately by each local government taxation authority. The provincial government sets school tax rate and no change is expected in 2005. Other property taxes are collected by local government taxation authorities on behalf of other taxation authorities such as regional districts and hospitals and overall are not expected to increase in 2005.

Beyond the larger increases forecast transmission assets, normal year-to-year inflation in other categories and revenue-driven changes in the 1% tax no additional property tax increases are included. As indicated in the Application section, Terasen Gas seeks continuation of the deferral account treatment for variances in property taxes from forecast.

2. B.C. CORPORATION CAPITAL TAX (CCT)

Corporate Capital Tax Expense

On July 30, 2001, the Ministry of Finance of the Province of British Columbia announced that it would phase out the corporate capital tax on non-financial institutions over two years. With the elimination of the CCT by September 1, 2002, no provision for CCT expense has been made for the 2004 – 2008 period.

3. LARGE CORPORATIONS TAX (LCT)

LCT is calculated based on taxable capital determined pursuant to the applicable sections of the *Income Tax Act* at a rate of 0.175% for 2005 (0.200% for 2004) . For details, see Section A, Tab 6, Page 9. LCT is reduced by the Federal corporate surtax calculated in accordance with the applicable provisions of the *Income Tax Act*.

4. INCOME TAX EXPENSE

Income tax expense is determined based on taxable earnings calculated on the basis of revenues and costs in accordance with the applicable provisions of the *Income Tax Act*, multiplied by the combined provincial and federal income tax rates. For regulatory purposes, income tax expense is calculated following the taxes payable method of accounting for income taxes. For 2005, the combined corporate income tax rate is set at 35.62% (including 1.12% surtax), unchanged from 2004.

TERASEN GAS INC.

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	B.C.U.C. Account Number	2004 Approved	2005 Total Expenses	2005 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Taxes	305-010					
2							
3	1% in Lieu of General Municipal Tax		13,090	$13,178	$13,178	$88	
4							
5	General, School and Other		26,330	26,395	26,395	65	
8							
9			39,420	$39,573	$39,573	153	
10							
11	B.C. Corporation Capital Tax		0	0	0	0	
12							
13	Total		$39,420	$39,573	$39,573	$153	- Tab 1, Page 7

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2004 Rates (2005)	2005 ----Revised Rates----- Revised Revenue	2005 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$173,778	$184,276	($689)	$183,587	$9,809	- Tab 1, Page 7
3	Deduct - Interest on Debt	(104,319)	(111,230)	0	(111,230)	(6,911)	
4	Add- Non-Tax Ded. Expense (Net)	262	(367)	0	(367)	(629)	- Tab 6, Page 6
5							
6	Accounting Income After Tax	69,721	72,679	(689)	71,990	2,269	
7	Add (Deduct) - Timing Differences	(6,616)	(10,273)	0	(10,273)	(3,657)	- Tab 6, Page 6
8	Add - Large Corporation Tax	3,415	3,020	12	3,032	(383)	- Tab 6, Page 9
9							
10	Taxable Income After Tax	$66,520	$65,426	($677)	$64,749	($1,771)	
11							
12							
13	Income Tax Rate (Current Tax)	35.620%	35.620%	35.620%	35.620%	0.000%	
14	1 - Current Income Tax Rate	64.380%	64.380%	64.380%	64.380%	0.000%	
15							
16	Deferred Income Tax	0	0	0	0	0	
17							
18	Taxable Income (L10 : L14)	$103,324	$101,624	($1,051)	$100,573	($2,751)	
19							
20							
21	Income Tax- Current (L18 x L13)	$36,804	$36,198	($374)	$35,824	($980)	
22							
23	- Large Corporation Tax	3,415	3,020	12	3,032	(383)	- Tab 6, Page 9
24							
25	Total	$40,219	$39,218	($362)	$38,856	($1,363)	- Tab 1, Page 7
26							
27	REVENUE DEFICIENCY						
28	Earned Return			($689)	$183,587		- Tab 1, Page 7
29	Add - Income Taxes			(362)	38,856		- Tab 1, Page 7
30	Deduct - Utility Income Before Taxes,						
31	Present Rates			0	(223,494)		- Tab 1, Page 7
32	Corporate Capital Tax			0	0		
33							
34	Deficiency After Corporate Capital Tax			($1,051)	($1,051)		

TERASEN GAS INC.
NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	2004 Approved	2005	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME				
2					
3	Amortization of Deferred Charges	($411)	($1,017)	($606)	-Tab 3, Page 11.1
4					
5	Non-tax Deductible Expenses	673	650	($23)	
6					
7					
8					
9	Total Permanent Differences	$262	($367)	($629)	-Tab 1, Page 8
10					
11	TIMING DIFFERENCE ADJUSTMENTS				
12					
13	Depreciation	$79,296	$80,794	$1,498	- Tab 6, Page 7
14	Less - Vehicle Costs Charged to Depreciation Expense	0	0	0	
15	Amortization of Debt Issue Expenses	1,611	1,497	(114)	
16	Debt Issue Costs	(902)	(1,174)	(272)	
17	Capital Cost Allowance	(77,331)	(79,457)	(2,126)	- Tab 6, Page 8
18	Cumulative Eligible Capital Allowance	(1,500)	(1,168)	332	
19	Add Back Principle Portion of Coastal Facilities Lease Payments	1,063	0	(1,063)	
20	Unfunded Pension	900	215	(685)	
21	Overheads Capitalized Expensed for Tax Purposes	(9,753)	(9,879)	(126)	
22	Discounts on Debt Issue and Other	0	(1,101)	(1,101)	
23					
24	Total Timing Differences	($6,616)	($10,273)	($3,657)	-Tab 1, Page 8

($000)

Line No.	Particulars	2004 Approved	2005	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	Depreciation Provision				
2					
3	Total Depreciation Expense	$89,103	$90,736	$1,633	- Tab 3, Page 13.3
4					
5	Less: Amortization of Contributions in Aid of Construction	(9,807)	(9,942)	(135)	- Tab 3, Page 8
6		79,296	80,794	1,498	
7					
8	- Vehicle Costs Charged to Depreciation Expense	0	0	0	
9					
10		79,296	80,794	1,498	
11					
12	Amortization Expense				
13					
14	Amortization of Deferred Charges	($411)	($1,017)	($606)	- Tab 3, Page 11.1
15					
16					
17		(411)	(1,017)	(606)	
18					
19	TOTAL	$78,885	$79,777	$892	- Tab 1, Page 7

TERASEN GAS INC.
CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Class	CCA Rate %	12/31/2004 UCC Balance	2005 Net Additions	2005 CCA	12/31/2005 UCC Balance
(1)	(2)	(3)	(4)	(5)	(6)
1	4%	$1,287,584	$78,349	($53,070)	$1,312,863
2	6%	$223,681	0	(13,421)	210,260
3	5%	$3,653	0	(183)	3,470
6	10%	$347	0	(35)	312
8	20%	$21,049	4,449	(4,655)	20,843
9	25%	$2	0	(1)	1
10	30%	$19,842	7,799	(7,122)	20,519
12	100%	$0	0	0	0
13		$6,919	0	(919)	6,000
14		$12	0	(2)	10
17	8%	$339	0	(27)	312
29	100%	$0	0	0	0
38	30%	$72	0	(22)	50
39	25%	$1	0	0	1
	Total	$1,563,501	$90,597	($79,457)	$1,574,641

TERASEN GAS INC.

CALCULATION OF LARGE CORPORATION TAX
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Reference	2004 Approved	2005 2004 Rates	2005 Revised Rates	Change
	(1)	(2)	(3)	(4)	(5)	(6)
1	Large Corporation Tax					
2						
3	Utility Capital (Line 26)		2,314,632	$2,412,826	$2,412,830	98,198
4	Add: Security Deposits		3,966	2,629	2,629	(1,337)
5	Long Term Construction Advances		525	1	1	(524)
6	Deferred Income Tax		364	364	364	0
7	Work in Progress Attracting AFUDC		14,000	7,628	7,628	(6,372)
8	Sub-total		2,333,487	2,423,448	2,423,452	89,965
9						
10	Utility Portion of $10,000,000 or $50,000,000 Deduction					
11	(Line 38 x $10,000,000 or $50,000,000)		(47,345)	(47,505)	(47,505)	(160)
12						
13	Taxable Capital		$2,286,142	$2,375,943	$2,375,947	$89,805
14						
15	Large Corporation Tax Rate		0.200%	0.175%	0.175%	-0.025%
16						
17	Large Corporation Tax		$4,572	$4,158	$4,158	(414)
18	Less: Surtax	1.12%	(1,157)	(1,138)	(1,126)	31
19						
20	Large Corporation Tax		$3,415	$3,020	$3,032	($383)
21						
22						
23	Net Plant in Service, Ending	Tab 1, Page 6	2,203,763	$2,295,282	$2,295,282	91,519
24	All Other Rate Base Items - Lines 26 - 31 of	Tab 1, Page 6	110,869	117,544	117,548	6,679
25						
26	Utility Capital		2,314,632	2,412,826	2,412,830	98,198
27						
28	Non-Rate Base Items					
29	Net Book Value of Lower Mainland Premium		116,708	114,700	114,700	(2,008)
30	Disallowed Plant Costs		2,344	2,090	2,090	(254)
31	Plant Held for Future Use		0	0	0	0
32	Fort Nelson Division		4,284	4,103	4,103	(181)
33	Squamish Gas Co. Ltd.		6,550	5,900	5,900	(650)
34						
35	Total Capital		$2,444,519	$2,539,619	$2,539,623	$95,105
36						
37						
38	Proportion of Utility Capital to Total Capital		94.69%	95.01%	95.01%	0.32%

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2005 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-7 INDEX

Under the terms of the 2004 – 2007 PBR Settlement the short term interest rate and new long term issues will be updated each fall for the Annual Review process. The interest deferral account will collect short term rate variances and all variances with respect to long term issues.

Long-Term Debt

A $220 million long-term debt issue with a coupon rate of 6.25% is planned for September 30, 2005.

The rollover of 2003 mid-term debt issue of $150 million is planned for September 27, 2005.

As noted under Section B, Tab 7, Terasen Gas has included the Coastal Facilities assets in rate base effective January 1, 2005. The Company expects to collapse the current lease arrangement and finance the Coastal Facilities assets with a conventional mix of $33.7 million long-term debt and $16.6 million common equity, as the cost of debt in the synthetic lease is moderately higher than the cost of debt achievable through the issuance of conventional debt. The remaining $16.6 million of long-term debt will be used to replace short-term borrowings. For 2005, the long term debt rate is expected to be 6.1%.

Unfunded Debt

The unfunded debt rate for 2005 is set at 4.00% based on the current outlook for short-term rates in the year.

Common Equity

The calculations in this Application have made use of an ROE of 9.15%, the same as the BCUC approved 2004 ROE. The 2005 rates applied for in this Application will be adjusted for any differences between 9.15% and the approved ROE arising from the BCUC ROE adjustment mechanism, which will be set in December 2004.

TERASEN GAS INC.

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	12-03-1990	09-30-2015	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	11-30-1991	11-30-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2003 Medium Term Note -Series 17	09-26-2003	09-26-2005	3.024%	150,000	474	149,526	4.516%	110,548	4,992	
5	2004 Long Term Debt Issue	04-29-2004	05-01-2034	6.500%	150,000	1,856	148,144	6.595%	150,000	9,893	
6	2005 Long Term Debt Issue	09-30-2005	09-30-2015	6.250%	220,000	2,200	217,800	6.387%	55,452	3,542	
7	2005 Long Term Debt Issue - Coastal Facilities	01-01-2005	01-01-2008	6.100%	50,300	50	50,250	6.113%	50,300	3,075	
8	2003 Medium Term Note - Series 17 Rollover	09-27-2005	09-28-2007	4.350%	150,000	474	149,526	4.516%	39,041	1,763	
9	Series F Debentures	08-26-1992	08-26-2002	8.500%	83,980	984	82,996	8.678%	0	0	
10	Series H Debentures	07-28-1993	07-28-2003	8.150%	50,000	507	49,493	8.301%	0	0	
11											
12	Medium Term Note - Series 6	02-09-1995	02-09-2005	9.800%	20,000	380	19,620	10.106%	2,192	222	
13	Medium Term Note - Series 6	03-15-1995	02-09-2005	9.800%	20,000	(387)	20,387	9.494%	2,192	208	
14	Medium Term Note - Series 7	06-29-1995	06-29-2005	8.250%	5,000	100	4,900	8.550%	2,466	211	
15											
16	Medium Term Note - Series 9	10-21-1997	06-02-2008	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
17	Med.Term Note - Series 9 (Re-opened)	11-19-1998	06-02-2008	6.200%	58,000	681	57,319	6.036%	58,000	3,501	
18	Med.Term Note - Series 9 (Re-opening)	09-21-1999	06-02-2008	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
19	Medium Term Note - Series 11	09-21-1999	09-21-2029	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
20											
21	Medium Term Note - Series 12	07-20-2000	07-20-2005	6.500%	200,000	2,622	197,378	6.814%	110,137	7,505	
22	Medium Term Note - Series 13	10-16-2000	10-16-2007	6.500%	100,000	728	99,272	6.632%	100,000	6,632	
23	Medium Term Note - Series 14	10-23-2000	10-23-2003	6.000%	50,000	428	49,572	6.317%	0	0	
24	Medium Term Note - Series 15	12-11-2000	12-11-2002	6.000%	75,000	229	74,771	6.177%	0	0	
25	Medium Term Note - Series 16	07-30-2001	07-31-2006	6.150%	100,000	887	99,113	6.360%	100,000	6,360	
26	LILO Obligations - Kelowna							6.969%	29,990	2,090	
27	LILO Obligations - Kelowna Addition							5.383%	788	42	
28	LILO Obligations - Nelson							5.924%	5,156	305	
29	LILO Obligations - Vernon							7.155%	15,516	1,110	
30	LILO Obligations - Prince George							6.230%	39,434	2,457	
31									$1,367,429	$96,464	
32	Debentures										
33	Series D	12-17-1986	12-17-2006	9.750%	20,000	244	19,756	9.945%	20,000	1,989	
34	Series E	06-08-1989	06-07-2009	10.750%	59,890	637	59,253	10.927%	59,890	6,544	
35									79,890	8,533	
36											
37	Sub-Total								1,447,319	104,997	
38	Less - Fort Nelson Division Portion of Long Term Debt								(2,635)	(191)	
39	Total								$1,444,684	$104,806	7.255%

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2005 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-8 INDEX

Before consideration of the 2003 restructuring cost, Terasen Gas is projecting a 2004 return on common equity of 9.94%, or 0.79% higher than the authorized return of 9.15%. This is due primarily to productivity improvements made possible by the performance based regulation settlement. After the restructuring cost is taken into consideration, the 2004 projected return on common equity decreases to 9.12%. Pursuant to the Settlement, the net effect is a shortfall of earnings. Under the earnings sharing mechanism, Terasen Gas is to share equally with its customers earnings variances between authorized level of earnings as determined annually under the settlement and the actual earnings of the utility. Accordingly, customers portion of the 2004 earnings shortfall is $204,000. Details in support of this calculation can be found on Page 6 of this Tab. The company proposes to recover this from customers in 2005 via a rider.

The treatment of the restructuring cost is consistent with the terms of the Settlement which states that net restructuring costs incurred by the Company between July 1, 2003 and December 31, 2003 are to 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 2003 net restructuring cost amounted to $9,571,000 (see Section B-4, Tab 4) and has been expensed in 2004 accordingly.

In summary, customer’s share of the 2004 earnings shortfall is projected to be $204,000 pre-tax. However, before the accounting for restructuring cost, the customer’s share of the earnings surplus would have been $4,582,000. It is important to note that the restructuring deferral account is a non-recurring item whereas productivity improvements are ongoing through the negotiated period so Terasen Gas anticipates future positive earnings sharing with customers.

TERASEN GAS INC.
UTILITY RATE BASE
SCHEDULE II
($000)

Line No.	Description	2004 Approved	2004 Projected	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in service, Beginning	$2,816,944	$2,817,464	$520	
2	CPCN's	10,117	14,075	3,958	
3					
4	Additions/Transfers	112,914	103,643	(9,271)	
5	Disposals/Retirements	(21,139)	(27,904)	(6,765)	
6	Plant in service, Ending	$2,918,836	$2,907,278	($11,558)	
7					
8	Add - Intangible plant	837	837	0	
9		$2,919,673	$2,908,115	($11,558)	
10					
11	Contributions in aid of construction	(149,325)	(149,493)	(168)	
12					
13	Less - Accumulated depreciation / amortization	(566,585)	(561,719)	4,866	
14					
15	Net plant in service, Ending	$2,203,763	$2,196,903	($6,860)	
16					
17	Net plant in service, Beginning	$2,177,251	$2,180,284	$3,033	
18					
19	Net plant in service, Mid-year	$2,190,507	$2,188,594	($1,913)	
20	Adjustment to 13-month average	0	(6,534)	(6,534)	
21	Work in progress, no AFUDC	4,000	11,597	7,597	
22	Sub-total	2,194,507	2,193,657	(850)	
23					
24	Construction advances	(750)	(415)	335	
25	Unamortized deferred charges	25,610	23,283	(2,327)	
26	Cash working capital	(18,804)	(15,023)	3,781	
27	Other working capital	101,177	119,652	18,475	
28	Deferred income tax, mid-year	(364)	(364)	0	
29	Capital Incentive Mechanism	0	0	0	
30	LILO Benefit	(1,510)	(1,634)	(124)	
31	**Utility rate base**	$2,299,866	$2,319,156	$19,290	

TERASEN GAS INC.
UTILITY INCOME AND EARNED RETURN
($000)

Line No.	Description	2004 Approved	2004 Projected	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUMES (TJ)**				
2	Sales	$120,165	$112,608	($7,557)	
3	Transportation	131,274	105,153	(26,121)	
4	Total	$251,439	$217,761	($33,678)	
5					
6	Average Rate per GJ				
7	Sales	$11.106	$10.837	($0.269)	
8	Transportation	$0.494	$0.644	$0.150	
9	Average	$5.566	$5.915	$0.349	
10					
11	**UTILITY REVENUE**				
12	Sales - Present Rates	$1,317,543	$1,220,360	($97,183)	
13	- Increase	17,005	0	(17,005)	
14	Transportation - Present Rates	62,758	67,716	4,958	
15	- Increase	2,145	0	(2,145)	
16	**Total Revenue**	1,399,451	1,288,076	(111,375)	
17					
18	Cost of Gas Sold (Including Gas Lost)	923,993	829,046	(94,947)	
19	**Gross Margin**	475,458	459,030	(16,428)	
20	RSAM Revenue	0	15,780	15,780	
21	**Adjusted Gross Margin**	475,458	474,810	(648)	
22					
23	Operation & Maintenance	159,417	157,135	(2,282)	
24	Operating Leases	6,372	6,360	(12)	
25	Property Tax	39,420	39,420	0	
26	Franchise Fees	0	0	0	
27	Depreciation and Amortization	78,885	77,131	(1,754)	
28	Other Operating Revenue	(22,633)	(21,700)	933	
29		261,461	258,346	(3,115)	
30	Utility Income before Income Taxes	213,997	216,464	2,467	
31	Income Taxes	40,220	40,814	594	- Tab 8, Page 4
32	**EARNED RETURN**	$173,777	$175,650	$1,873	
33	**UTILITY RATE BASE**	$2,299,866	$2,319,156	$19,290	- Tab 8, Page 2
34					
35	**RETURN ON RATE BASE**	7.556%	7.574%	0.018%	

TERASEN GAS INC.
INCOME TAXES
SCHEDULE III
($000)

Line No.	Description	2004 Approved	2004 Projected	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1	CALCULATION OF INCOME TAXES				
2	Earned Return	$173,777	$175,650	$1,873	
3	Deduct - Interest on Debt	(104,319)	(105,893)	(1,574)	
4	Add - Non-Tax Deductible Expense (Net)	262	239	(23)	
5					
6	Accounting Income After Tax	$69,720	$69,996	$276	
7	Deduct: Timing Differences	(6,616)	(7,798)	(1,182)	
8	Add: Large Corporation Tax	3,415	4,121	706	
9					
10	Taxable Income After Tax	$66,519	$66,319	($200)	
11					
12	Income Tax Rate (Current Tax)	35.620%	35.620%	0.000%	
13	1 - Current Income Tax Rate	64.380%	64.380%	0.000%	
14					
15	Taxable Income Before Income Tax	$103,326	$103,012	($314)	
16	Add - Amount Required to Provide for				
17	Deferred Income Tax	0	0	0	
18					
19	Taxable Income	$103,326	$103,012	($314)	
20					
21	Income Tax				
22	Current	$36,805	$36,693	($112)	
23	Deferred Income Tax	0	0	0	
24	Large Corporation Tax	3,415	4,121	706	
25					
26	Total	$40,220	$40,814	$594	- Tab 8, Page 3

TERASEN GAS INC.
RETURN ON CAPITAL
SCHEDULE IV
($000)

Line No.	Description	2004 Approved	2004 Projected	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1	Unfunded debt	$225,493	$210,402	($15,091)	
2	proportion	9.80%	9.07%	-0.73%	
3	rate of return	3.250%	3.250%	0.000%	
4	return component	0.32%	0.30%	-0.02%	
5					
6	Long term debt	$1,315,417	$1,343,432	$28,015	
7	proportion	57.20%	57.93%	0.73%	
8	rate of return	7.373%	7.373%	0.000%	
9	return component	4.22%	4.27%	0.05%	
10					
11	Preference shares	$0	$0	$0	
12	proportion	0.00%	0.00%	0.00%	
13	rate of return	0.000%	0.000%	0.000%	
14	return component	0.00%	0.00%	0.00%	
15					
16	Common equity	$758,956	$765,322	$6,366	
17	proportion	33.00%	33.00%	0.00%	
18	rate of return	9.150%	9.115%	-0.035%	
19	return component	3.02%	3.01%	-0.01%	
20					
21					
22		$2,299,866	$2,319,156	$19,290	
23					
24					
25	Return on rate base	7.556%	7.574%	0.018%	- Tab 8, Page 3
26					
27					
28	Utility rate base	$2,299,866	$2,319,156	$19,290	- Tab 8, Page 2

TERASEN GAS INC.
EARNINGS SHARING CALCULATION
($000)

Line No.	Description (1)		2004 Projected (2)	Reference (3)
1	Utility rate base		$2,319,156	- Tab 8, Page 2
2				
3	Common Equity Component	33.0%	765,322	- Tab 8, Page 5
4				
5				
6	Achieved ROE on Common Equity		9.115%	- Tab 8, Page 5
7				
8	Authorized ROE on Common Equity		9.150%	- Tab 8, Page 5
9				
10	ROE Surplus / (Deficit)		-0.035%	
11				
12	After Tax Deficit Available for Sharing		($268)	
13				
14				
15	Customers' 50% Share of Deficit (net-of-tax)		($134)	
16				
17				
18	**Customers' 50% Share of Deficit (pre-tax)**		**($204)**	

The 5 Year Major Capital Project Plan for Terasen Gas is presented below.

Major Capital Projects are defined in this plan as those discrete projects that are in excess of $1.0 million (excluding AFUDC).

1.0 PEAK LOAD PROJECTIONS

Terasen Gas operates two types of gas delivery systems delineated by operating pressure:

- Transmission systems operating in pressures in excess of 2,069 kPa and
- Distribution systems operating in pressures below 2,069 kPa.

The Terasen Gas transmission pressure system is divided into three subsets:

- the Coastal Transmission system
- the Interior Transmission system and
- the Transmission Pressure laterals from the Duke Energy Gas Transmission and TransCanada Pipeline systems.

The Terasen Gas distribution pressure system is divided into three subsets based on pressure range:

- the Intermediate Pressure systems operating between 690 - 2,069 kPa
- the Distribution Pressure systems operating between 114 - 690 kPa and
- the Low Pressure systems operating below 114 kPa.

The distribution pressure system is made up of approximately 15 Intermediate Pressure systems and 70 Distribution and Low Pressure systems.

Loads from the lower pressure distribution systems are rolled-up and are ultimately captured in the peak load projections for the transmission pressure system.

The following table shows the peak load projections (forecast design loads) used in this 5 Year Major Capital Project Plan 2005-2009 for the areas of capacity shortfalls.

Peak Load Projections (Forecast Design Loads) 2005 - 2009

Coastal Transmission System		**2005**	**2006**	**2007**	**2008**	**2009**
$10^3 m^3$/hr	Peak Hour	1,919	1,930	1,957	1,971	1,986

Interior Transmission System		**2005**	**2006**	**2007**	**2008**	**2009**
$10^3 m^3$/day	Peak Day	7,711	7,772	7,840	7,906	7,974

Note that the Peak Load Projection for the Interior Transmission System is stated on a daily rather than hourly basis to reflect the significant role played by the line pack for the Interior Transmission System.

2.0 AREAS OF CAPACITY SHORTFALL

2.1 Coastal Transmission System

Based on the Coastal Transmission System peak load projections (forecast design loads) for 2005-2009 there are no major projects that have been identified.

2.2 Interior Transmission System

Based on the Interior Transmission System peak load projections (forecast design loads) for 2005-2009 there are no major projects that have been identified.

2.3 Transmission Pressure Laterals

Based on the Transmission Pressure Laterals peak load projections (forecast design loads) for 2005-2009 there are no major projects that have been identified.

2.4 Intermediate Pressure Systems

Based on the Intermediate Pressure systems peak load projections (forecast design loads) for 2005-2009 the following major projects have been identified:

2.4.1 Riverside Road, Abbotsford

This project is currently planned to be constructed in 2006. It consists of a 1.6 km loop of 323mm O.D. pipeline operating at 1,900 kPa. The estimated cost of this project is $1.1 million (excluding AFUDC) and is expected to be in service in 2006.

2.4.2 72nd Street to 36th Avenue, Delta

This project is currently planned to be constructed in 2006. It consists of a 2.6 km loop of 323mm O.D. pipeline operating at 1,200 kPa. The estimated cost of this project is $1.8 million (excluding AFUDC) and is expected to be in service in 2006.

2.4.3 Goudy Road and 36th Avenue, Delta

This project is currently planned to be constructed in 2007. It consists of a 1.75 km loop of 323mm O.D. pipeline operating at 1,200 kPa. The estimated cost of this project is $1.2 million (excluding AFUDC) and is expected to be in service in 2007.

2.4.4 34B to 57th Avenue, Delta

This project is currently planned to be constructed in 2008. It consists of a 1.5 km loop of 323mm O.D. pipeline operating at 1,200 kPa. The estimated cost of this project is $1.0 million (excluding AFUDC) and is expected to be in service in 2008.

2.5 Distribution Pressure Systems

Based on the Distribution Pressure systems peak load projections (forecast design loads) for 2005 – 2009, there are no major projects that have been identified.

2.6 Low Pressure Systems

Based on the Low Pressure systems peak load projections (forecast design loads) for 2005 – 2009 there are no major projects that have been identified.

3.0 PROJECTS FOR SYSTEM MODIFICATION OR EXPANSION

3.1 Secondary Containment

To comply with Provincial and Federal legislation all storage containers that hold a volume greater than 205 litres of flammable or combustible liquid require secondary containment facilities.

In 2002 Terasen Gas embarked on a five year program to construct secondary containment facilities. The total estimated cost of this project is $9.2 million (excluding AFUDC) and is expected to be complete in 2006. The remaining expenditures are forecasted at: $2.1 million in 2005 and $2.4 million in 2006 (all estimates exclude AFUDC).

3.2 Fraser River Crossing, Vancouver

Recent updates of seismic performance studies of the 762mm and 609mm O.D. transmission pipelines crossing the Fraser River, between Tilbury and Richmond, indicate that the seismic capacity of both pipelines is insufficient. These pipelines supply approximately 2/3 of the gas supply to the Vancouver area.

A further seismic study to validate existing analysis was completed in 2004, and results indicate that these pipelines are at risk and require corrective action to bring seismic performance to current Terasen Gas standards. Replacement is currently viewed as one of the most effective means of mitigation, replacing both lines using directional drilling. Other potential mitigation measures are also currently being evaluated; the probability of these being effective is unknown at this time.

If replacement is selected as the best long-term option, the total estimated cost of this project to replace both crossings is $20.0 million (excluding AFUDC). The replacement of the two pipelines is planned to commence in 2005 and would be in service by year end 2005.

This project is expected to be the subject of a CPCN application.

4.0 COST PROJECTIONS FOR REGULAR CAPITAL AND CPCN'S

4.1 Cost Projections for Regular Capital

The following table identifies the cost projections for regular capital expenditures in 2005 – 2009.

Cost Projections for Regular Capital Expenditure 2005-2009

Customer Driven Capital	**2005**	**2006**	**2007**	**2008**	**2009**
Mains	5,129	5,351	5,036	5,036	5,384
Services	9,420	9,828	9,249	9,250	9,889
Meters - Customer Additions	3,006	3,106	2,894	2,867	3,035
	17,555	**18,284**	**17,180**	**17,153**	**18,307**
Other Regular Capital	**2005**	**2006**	**2007**	**2008**	**2009**
Meters - Replacement	14,786	15,192	15,695	16,156	16,792
System Integrity & Reliability					
Transmission Plant	5,436	5,121	5,932	6,051	4,704
Distribution Plant	11,874	16,856	8,999	9,179	7,533
Other Regular Capital					
Non - IT	11,444	11,692	11,946	12,222	12,466
IT	10,183	13,475	13,825	14,180	14,504
	53,723	**62,336**	**56,397**	**57,788**	**55,999**
Total Regular Capital	**71,278**	**80,621**	**73,576**	**74,941**	**74,307**

Note: All estimates exclude AFUDC

4.2 Cost Projections for CPCN's

The following table identifies the cost projections for major capital projects subject to CPCN applications for 2005 – 2009:

Cost Projections for Major Capital Projects Subject to CPCN Applications 2005-2009

CPCN Applications	**2005**	**2006**	**2007**	**2008**	**2009**
4.2.1 Transmission Pipeline Integrity Plan (TPIP)	3,723	-	-	-	-
4.2.2 Fraser River Crossing, Vancouver	20,000	-	-	-	-
	23,723	**-**	**-**	**-**	**-**

Note: All estimates exclude AFUDC

4.2.1 Transmission Pipeline Integrity Plan (TPIP)

The Transmission Pipeline Integrity Plan (TPIP) is part of an overall transmission system integrity management program that was developed to ensure that the transmission pipelines provide continued safe and reliable service.

The major components of the TPIP are:

- retrofits of the existing pipeline systems to allow the passage of In-Line Inspection tools which detect corrosion, dents and other anomalies
- repair programs
- rehabilitation programs
- development of a corrosion growth model that drives inspection and remediation

Since, 2001 CPCN applications have been submitted annually based on the general program and rehabilitation costs in the year of application and retrofit and tool run costs for the subsequent year.

Forecasted capital expenditures that are subject to CPCN applications in 2005 – 2009 are as follows:

- 2005 – Continued Coastal Transmission System retrofit to allow the efficient use of in-line inspection tools. The estimated cost is $3.7 million (excluding AFUDC).

Subsequent expenditure to complete the TPIP will be funded through the Company's other regular capital expenditures and operating and maintenance expenditures.

4.2.2 Fraser River Crossing, Vancouver

As detailed in Section 3.4 Projects for System Modification or Expansion Areas (above), forecasted capital expenditure for this project is subject to a CPCN application:

- 2005 – Fraser River Crossing. The total estimated cost of this project is $20.0 million (excluding AFUDC). The replacement of the two pipelines by directional drilling is planned to commence in 2005 and would be in service by year end 2005.

5.0 SCHEDULING OF PROJECTS

The following table shows the scheduling and cost projections of the major capital projects by year from 2005 - 2009.

Scheduling and Cost Projections of Major Capital Projects 2005-2009

Other Regular Capital Transmission and Distribution Plant	**2005**	**2006**	**2007**	**2008**	**2009**
3.1 Secondary Containment	2,100	2,389	-	-	-
2.4.1 Riverside Road, Abbotsford	-	1,100	-	-	-
2.4.2 72nd St to 36th Avenue, Delta	-	1,800	-	-	-
2.4.3 Goudy Road and 36th Avenue, Delta	-	-	1,211	-	-
2.4.4 34B to 57th Avenue, Delta	-	-	-	1,038	-
	2,100	**5,289**	**1,211**	**1,038**	**-**

Other Regular Capital Non-IT and IT	**2005**	**2006**	**2007**	**2008**	**2009**
5.1 SAP Core Application Upgrade	500	2,000	-	-	-
5.2 SCADA System Upgrade	-	1,500	-	-	-
	500	**3,500**	**-**	**-**	**-**

CPCN Applications	**2005**	**2006**	**2007**	**2008**	**2009**
4.2.1 Transmission Pipeline Integrity Plan (TPIP)	3,732	-	-	-	-
4.2.2 Fraser River Crossing, Vancouver	20,000	-	-	-	-
	23,732	**-**	**-**	**-**	**-**

Note: All project estimates exclude AFUDC

5.1 SAP Core Application Upgrade

SAP is the enterprise application that supports business processes for: Operate and Maintain; Order Fulfillment; Meter Management and Supply Chain. It also supports other back-office functions such as: Payroll; Finance and Performance Reporting. Vendor support of the current version of the SAP application (R3 v4.6C) expires in Q4 2006. An upgrade to the next supported version is therefore required to be in service in 2006. The total estimated cost of this project is $2.5 million (excluding AFUDC). Implementation is expected to begin in 2005 and will be completed in 2006.

5.2 SCADA System Upgrade

The SCADA system operates controls and monitors Terasen Gas' transmission and compression facilities in British Columbia. Vendor support of the current version (6.0) of the SCADA application is expected to expire at the end of 2007. An upgrade to the next supported version is therefore required to be in service in 2007. The total estimated cost of this project is $1.5 million (excluding AFUDC). Implementation is expected to begin in Q1 2007 and will be completed in Q4 2007.

6.0 CPCNS THAT MAY BE NEEDED IN FUTURE YEARS

The 5 Year Major Capital Project Plan is updated on an annual basis. Projections for projects that fall outside of the five year timeframe are not subject to detailed project estimating due to the uncertainties in projecting the economic and business environments, and population growth.

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
SERVICE QUALITY ASSURANCE MECHANISM

1 INTRODUCTION

In 2003, the BC Utilities Commission approved the 2004 – 2007 PBR Settlement that Terasen Gas Inc. negotiated with its stakeholders. This agreement includes a commitment to maintaining specified levels of service as measured by Service Quality Indicators (SQIs).

Terasen Gas has ten SQIs that are measured and compared against benchmarks on an annual basis. Also included are two directional indicators that do not have benchmarks but are designed to give an understanding of trends that may develop in these areas relating to customer service.

2 COMPONENTS OF THE SERVICE QUALITY ASSURANCE MECHANISM

The Service Quality Assurance Mechanism includes four components:

1. A set of ten service quality indicators;
2. Benchmarks for each indicator;
3. Two directional indicators; and
4. A process for reviewing Terasen Gas performance.

2.1 Service Quality Indicators and Benchmarks

2.1.1 Choice of Service Quality Indicators

Service Quality Indicators are generally based on the following criteria:

- Value to customer: The indicator must represent a service or service attribute that the customer thinks is important.
- Controllable by the utility: Only those indicators over which the utility has control should be included. SQI's should not be linked to exogenous events over which management decisions have little or no influence.

- Cost effective: The information collection activities associated with the indicator must be cost effective.
- Regulated service: The indicator must represent a regulated service provided by the utility that is not generally available from competitors.
- Simplicity and transparency: The indicator should be simple to administer and results should be easy to understand and interpret.
- Prior tracking: The indicators should have been previously tracked to ensure they are stable over time and this should be considered in future evaluations.
- Quantification: The indicators must be quantifiable.
- Flexibility: The indicators should allow sufficient flexibility to allow modifications, additions and deletions as required over time.

2.1.2 History of Service Quality Indicators

The criteria described in the previous section were taken into account in establishing the Service Quality Indicators for the PBR settlement in 1997. Five Service Quality Indicators were used between 1998 and 2002:

1. Response time to site for emergency calls (only for the Coastal region).
2. Percent of responses within 30 seconds by a person at a call centre (only for the Coastal region).
3. Leaks per kilometre of Distribution mains due to system deterioration.
4. Transmission system annual reportable incidents.
5. Number of third party distribution system damage incidents per 1000 housing starts.

During the 2004-2007 PBR Settlement process, the Service Quality Indicators were reviewed and substantially changed. The criteria described in the previous section were also taken into account in establishing the Service Quality Indicators for the 2004 – 2007 period.

2.1.3 Choice of Benchmarks

Benchmarks are reference points against which levels of service quality can be compared. Benchmarks typically reflect either industry standards or the utility's performance over a recent prior period. Use of the utility's recent historical performance to establish a benchmark is generally used as this has the advantage of being realistic, verifiable, and representative.

2.1.4 Service Quality Indicators and Benchmarks

There were many changes and additions to the Service Quality Indicators as part of the 2004 – 2007 PBR Settlement. The following are individual explanations for each of the ten SQIs that were established during the 2004 – 2007 PBR Settlement to be used throughout the PBR period. Please refer to the table at the end of this section for a summary of the SQIs.

1. Emergency Response Time
(Response Time Dispatched to Site for Emergency Calls)

This indicator is the average length of time after notification for a qualified utility representative to arrive on the scene of the emergency (i.e. a pulled main or a situation where gas is blowing) at any location on the Terasen Gas system both during and after working hours. The benchmark was set at the average for the three years from 2000 to 2002: 21.1 minutes. Information for the Interior System has become available only recently, but this information was researched back to 2000 in order to set the benchmark.

Year	Response Time Dispatched to Site for Emergency Calls
2004 (Jan – Sep)	21.5 minutes
2003	22.0 minutes
2002	20.5 minutes
2001	21.7 minutes
2000	21.2 minutes
Benchmark	21.1 minutes

The 2004 year-to-date response time of 21.5 minutes is 0.4 minutes longer than the benchmark of 21.1 minutes. While this exceeds the benchmark, the variance is less than 2% and represents an improvement over 2003. Over the five-year period shown above, the five-year average is 21.4 minutes. Terasen Gas submits that this SQI is within the range of values experienced over the past five years and there is no significant deterioration in service quality.

2. Speed of Answer – Emergency (Percent of responses within 30 seconds by a Person - Emergency Calls)

The amount of time it takes for the telephone to be answered is a common service quality indicator. Emergency Call Handling for the Lower Mainland Call Centre was a Service Quality Indicator from 1998 to 2002. The introduction of the Interior call centre allowed Terasen Gas to track the Percent of Responses within 30 seconds by a Person for Emergency Calls for both the Coast and Interior since 2000. The benchmark of 95.0% is based on the performance clause in the contract with CustomerWorks. Note the benchmark is an improvement over the three-year historical average.

Year	Percent of responses within 30 seconds by a Person for Emergency Calls
2004 (Jan - Sept)	97.6%
2003	96.3%
2002	95.9%
2001	91.2%
2000	90.3%
Benchmark	95.0%

The 2004 year-to-date percentage for Emergency Speed of Answer at 97.6% is an improvement over the benchmark of 95.0% and continues the favourable trend of the past five years.

3. Speed of Answer – Non Emergency (Percent responses within 30 seconds by a Person - Non-Emergency Calls)

This SQI tracks the percent of responses within 30 seconds by a person for non-emergency calls including general, bill inquiries and service applications. B.C. Hydro answered the majority of Lower Mainland non-emergency inquiries prior to repatriation in July 2002. The introduction of the Interior call centre allowed Terasen Gas to track the Percent of Responses within 30 seconds by a Person for Emergency Calls for both the Coast and Interior since 2000. The benchmark of 75.0% is based on the performance clause in the contract with CustomerWorks and the average for the three years from 2000 to 2002.

Year	Percent of responses within 30 seconds by a Person for a Non-Emergency Call
2004 (Jan - Sept)	77.6%
2003	76.4%
2002	73.8%
2001	79.0%
2000	72.0%
Benchmark	75.0%

The 2004 year-to-date percentage for Non-Emergency Speed of Answer at 77.6% is an improvement over the benchmark of 75.0%.

4. Transmission System Integrity (Transmission System Annual Reportable Incidents)

This indicator is presently tracked manually and this is expected to continue, as it covers several different kinds of incidents that are reported to government.

Year	Transmission System Annual Reportable Incidents
2004 (Jan - Sept)	1
2003	3
2002	1
2001	2
2000	3
Benchmark	2

The 2004 year-to-date Transmission Reportable Incidents of 1 is less than the benchmark of 2.

5a. Residential & Commercial Customer Billing Activity (Customer Bills Produced meeting Activity Criteria)

This indicator is new for the 2004 – 2007 PBR. The contract with CustomerWorks contains three performance measures that are included together as sub-measures and combined to form a single service quality indicator. These sub-measures are generally described as accuracy, timeliness and completion. The tolerance requirements for the first measure are significantly higher than the second and third, 99.9% vs. 95%. As such, in order to align these sub-measures, an "Adjustment" is used. The objective is to achieve a score of 5.0 or less. The Adjustment formula was shown incorrectly in the Settlement Document, but the formula was shown correctly in the Application and it is repeated here in that form. No historical information is available prior to 2003 but the benchmark is set based on the performance measures in the contract with CustomerWorks.

	Billing Sub-Measure	Percent Achieved ("PA")	Adjustment Factors	Result
1	Percentage of bills accurate based upon input data	99.9%	IF [PA≥99.9%, 5000*(1-PA), 100*(1.05-PA)]	5.0
2	Percentage of bills delivered to Canada Post within two days of date that the statement file is created	95%	100 – PA	5.0
3	Percentage of customers billed within two business days of the scheduled billing date	95%	100 – PA	5.0
Benchmark	Billing Service Quality Indicator (arithmetic average of sub-measures 1 to 3)			5.0

The Adjustment Factors allow the computation of an index score using a simple average of the three results (5.0 or less is desirable).

Year	Customer Bills Produced meeting Activity Criteria
2004 (Jan - Sept)	1.97
2003	2.63
Benchmark	5.0

The 2004 year-to-date result for customer bills meeting criteria at 1.97 is an improvement over the benchmark of 5.0 and an improvement over the 2003 level of 2.63.

5b. Industrial Customer Billing Activity (Percent of Industrial Customer Bills Accurate)

This indicator is new for the 2004-2007 PBR. Historical information is only available beginning in 2003. This service quality indicator tracks the accuracy of billing for Industrial customers.

Year	Percent of Industrial Customer Bills Accurate
2004 (Jan - Sept)	96.0%
2003	99.8%
Benchmark	99.5%

The 2004 year-to-date percentage of industrial bills accurate of 96.0% does not meet the benchmark of 99.5%. The May 2004 monthly result reflected one-time start-up issues associated with implementing the new automated billing system. These issues were resolved, and processes have been put in place to ensure against their recurrence. The May results were significant enough to affect the year-to-date results for 2004, and they will affect the year-end results for 2004. However, with the implementation of process changes, this SQI has been tracking within target since July and this trend is expected to continue. If the monthly results for May are excluded from the 2004 year-to-date results, the measure (at 99.7%) meets the benchmark.

6. Meter Exchange Appointment Activity (Percent of Appointments Met for Meter Exchange)

This indicator is new for the 2004-2007 PBR and it tracks the percent of appointments met for meter exchange. Terasen Gas started to track this information with the introduction of the Integrated Resource Management project in late 2001, so historical information is available only since 2002. The benchmark is set at the 2002 level.

Year	Percent of Appointments Met for Meter Exchange
2004 (Jan - Sept)	94.1%
2003	92.6%
2002	92.2%
Benchmark	92.2%

The 2004 year-to-date result of 94.1% of meter exchange appointments met is an improvement over the benchmark of 92.2% and an improvement over the 2003 level of 92.6%.

7. Industrial Meter Measurement (Industrial Meter Measurement First Report under 10%)

This indicator is new for the 2004 – 2007 PBR. This service quality indicator tracks the percent of time when the deviation is less than 10% between the preliminary billing estimate that is first reported to an industrial customer, compared to the final amount that is billed to the customer. Industrial Shipper Agents are interested in both their daily balanced groups and their monthly balanced groups. This SQI for Industrial Meter Measurement contains both an accuracy measure (percent deviation) and a frequency measure, applied to both daily and monthly groups on a GJ-weighted basis. Customers who do not provide Terasen with a metering phone line are not included in this measure. Historical information is only available beginning in 2003. The benchmark is set at 90%.

Year	Industrial Meter Measurement First Report under 10%
2004 (Jan - Sept)	97.0%
2003	97.4%
Benchmark	90.0%

The 2004 year-to-date result of 97.0% for industrial meter measurement is an improvement over the benchmark of 90.0% and approximately the same as the 2003 level of 97.4%.

8. Customer Satisfaction (Independent Customer Satisfaction Survey)

This indicator is new for the 2004-2007 PBR. This service quality indicator tracks customer satisfaction using three surveys conducted by parties outside Terasen Gas. A residential survey is conducted quarterly, while a large commercial survey and a builder/developer survey are conducted annually. In order to arrive at the Service Quality Indicator for the Independent Customer Satisfaction Survey, these three surveys are weighted as follows: 80% Residential, 10% Commercial and 10% Builder/Developer. High gas costs and other events beyond the control of Terasen Gas can influence this SQI; it was agreed during the 2004 – 2007 PBR Settlement, that evaluation by the parties of annual results will consider 2003 results and any relevant uncontrollable events.

Year	Independent Customer Satisfaction Survey
2004 (Jan - Sept)	73.8%
2003	73.9%
Benchmark	To be compared to 2003

The 2004 year-to-date customer satisfaction survey of 73.8% is 0.1% lower the prior year. According to the independent market research firm who conducts the surveys, the difference in results is not statistically significant. As such, Terasen Gas submits that there is no deterioration in service quality.

9. Customer Satisfaction (Number of Customer Complaints to BCUC)

This service quality indicator is new for the 2004-2007 PBR. This indicator tracks the number of customer complaints submitted to the BCUC that the Commission then requests, either by Commission Letter or by a Complaint/Inquiry Record, that Terasen Gas provide a written response. Historical information is only available beginning in 2003. High gas costs and other events beyond the control of Terasen Gas can influence the number of complaints to the BCUC; it was agreed during the 2004 – 2007 PBR Settlement, that evaluation by the parties of annual results will consider 2003 results and any relevant uncontrollable events

Year	Number of Customer Complaints to BCUC
2004 (Jan - Sept)	158
2003	101
Benchmark	To be compared to 2003

The 2004 year-to-date customer complaints to BCUC of 158 exceeds the 2003 total of 101. 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.

	2003	2004 YTD
Billing	44	43
Service	8	23
Collections	37	85
Other	12	7
Totals	101	158

Terasen Gas submits that given the nature of the complaints, the fact that the numbers have increased does not indicate a deterioration in service quality. The Company's actions on billing and collection matters have been taken to balance the interests of all customers and while not always appreciated by the individuals directly affected, they are appropriate in the circumstances.

10. Customer Satisfaction (Number of Prior Period Adjustments)

This service quality indicator is new for the 2004-2007 PBR. This indicator tracks the number of prior period adjustments for Industrial Transportation Service customers. A prior period adjustment is a billing inaccuracy that is identified after a bill has been issued; if this occurs, the bill is adjusted with any necessary corrections. Historical information is only available beginning in 2003. High gas costs and other events beyond the control of Terasen Gas can influence this SQI; it was agreed during the 2004 – 2007 PBR Settlement, that evaluation by the parties of annual results will consider 2003 results and any relevant uncontrollable events

Year	Number of Prior Period Adjustments
2004 (Jan - Sept)	15
2003	24
Benchmark	To be compared to 2003

The 2004 year-to-date prior period adjustments result of 15 is less than the benchmark of 24, and is projected to be less than the benchmark at year-end.

2.1.5 <u>Directional Indicators</u>

Two of the previous Service Quality Indicators were not effective as measures but they are included as Directional Indicators.

1. Number of Third Party Damages

Terasen Gas continues its efforts in preventing third party damages to the distribution system. There is no direct link between Third Party Damages and housing starts, so "Number of Third Party Damages" is tracked and reported as a Directional Indicator, with no benchmark.

Year	Number of Third Party Damages
2004 (Jan - Sept)	1193 incidents
2003	1459 incidents
2002	1242 incidents
2001	1132 incidents
2000	1284 incidents

The 2004 year-to-date number of third party damages at 1193 incidents is less than 2003 and is projected by year-end to be at the high end of the range of previous years due to the high level of construction activity.

2. Leaks per Kilometre of Distribution Mains

The number of leaks may measure integrity to a certain extent, but in practice, there is an apparent incentive to lengthen the frequency between surveys in order to reduce the number of leaks detected. Each year approximately one-fifth of the Distribution System is surveyed for leaks. The number of leaks found will vary, in the short term, more because of the condition of the portion of the system being surveyed in the given year than it will be affected by the quality of the current maintenance program. This statistic will only become valid over a much longer time horizon; probably 15 to 25 years. Terasen Gas believes it should be detecting as many existing leaks as reasonably possible so the results of this measure may run somewhat contrary to the true objective. This measure will continue to be tracked manually and reported as a Directional Indicator, with no benchmark.

Year	Leaks per Km of Distribution Mains
2004 (Jan - Sept)	0.0036 (121 leaks)
2003	0.0040 (134 leaks)
2002	0.0043 (160 leaks)
2001	0.0034 (126 leaks)
2000	0.0046 (170 leaks)

The 2004 year-to-date number of leaks per km of distribution mains of 121 leaks is projected by year-end to be within the range of previous years.

2.1.6 Conclusion

It is Terasen Gas' view that service quality has been maintained in 2004.

2.2 Summary of Service Quality Indicators

	Performance Measure	Service Quality Indicator	Benchmark
1	Emergency Response Time	Response Time Dispatched to Site for Emergency Calls	21.1 minutes
2	Speed of Answer - Emergency	Percent of responses within 30 seconds by a Person for Emergency Calls	95.0%
3	Speed of Answer - Non Emergency	Percent of responses within 30 seconds by a Person for Non Emergency Calls	75.0%
4	Transmission System Integrity	Transmission System Annual Reportable Incidents	2
5a	Residential & Commercial Customer Billing Activity	Percent of Customer Bills Produced Meeting Accuracy, Timeliness and Completion	5.0
5b	Industrial Customer Billing Activity	Percent of Industrial Customer Bills Accurate	99.5%
6	Meter Exchange Appointment Activity	Percent of Appointments Met for Meter Exchange	92.2%
7	Industrial Meter Measurement	Industrial Meter Measurement First Report under 10%	90.0%
8	Customer Satisfaction	Independent Customer Satisfaction Survey	To be compared to 2003
9	Customer Satisfaction	Number of Customer Complaints to BCUC	To be compared to 2003
10	Customer Satisfaction	Number of Prior Period Adjustments	To be compared to 2003

2.2 Summary of Directional Indicators

	Directional Measure	Directional Indicator
1	Distribution System Integrity	Number of Third Party Damages
2	Distribution System Integrity	Leaks per Kilometre of Distribution Mains

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
2004 DSM STATUS REPORT

1. INTRODUCTION

Under the terms of the 2004 – 2007 Multi-Year PBR Settlement, Terasen Gas is required to submit an annual Demand Side Management (“DSM”) Status Report to the Commission as part of the Annual Review process. This report follows the 2003 Status report in form and content and provides an overview of Terasen Gas’ DSM activities in 2004 with details pertaining to the progress of individual DSM programs against forecasted targets and objectives for the year. As in prior years, Terasen Gas has offered several types of programs most of which are in progress at the time of this writing; therefore, impacts are estimated rather than actual results.

2. OVERVIEW OF DSM PROGRAMS AT TERASEN GAS

In 2004, Terasen Gas has continued efforts to promote natural gas conservation and efficiency to its customers through a combination of awareness, education and incentive programs.

Energy conservation and efficiency is also being promoted by a number of other utilities, agencies and industry members: Terasen Gas has attempted, whenever feasible, to partner with others to leverage utility DSM funds. Proposed programs are subjected to economic cost-benefit tests (most notably a standardized Total Resource Cost test) prior to launch and, when completed, major initiatives are subjected to third party evaluations. The evaluations have proved to be an important tool for process improvement (for example, by indicating delivery problems that should be corrected if the program is to be made available in the future) and for determining if the actual impact of the program is sufficient (for example, by measuring actual natural gas savings). In the case of programs where the energy savings measures adopted by the customer are significant, as would be the case if a furnace or boiler is changed to a high efficiency model, Terasen Gas has utilized analysis of customer billing data.

DSM initiatives may also produce benefits for the utility, the customer, and society in general which are not considered as part of the Total Resource Cost test. Of particular interest are the resulting reduced emissions that result from reduced natural gas consumption—contributing to improved local air quality and a reduction in greenhouse gases.

3. PRIOR YEARS INITIATIVES EVALUATION

In 2004, two programs were evaluated:

Billing Analysis - 2002 Residential Heating System Upgrade Program Evaluation
Habart & Associates Consulting Inc.
July 28, 2004

This report, an Addendum to the 2002 Heating Upgrade Evaluation, provided two items which were not included in the earlier evaluation of the 2002 program:

- Discrete Choice Analysis to determine attribution and
- Billing Analysis to determine the energy impact of the program.

The most significant finding was evidence indicating that the average AFUE efficiency of furnaces removed is likely closer to 70%--much higher than the previously assumed 60%. The study also concluded that participants replaced their heating equipment on average 4.5 years sooner than they would have without an incentive program in place. These findings along with other key points of the evaluation provide valuable input to future heating system upgrade programs. A complete copy of the evaluation is attached as Appendix A.

Final Report - Impact of Terasen Gas/Energy Star Heating System Upgrade (2003) Program,
Habart & Associates Consulting Inc.
August 2004

Building on the previous studies in 2001 and 2002, the 2003 program evaluation focused on aspects of the heating system upgrade program that had not been previous evaluated. Thirteen conclusions were highlighted as part of the evaluation—not the least of which was the evidence of market transformation: market share of high efficiency furnaces in the retrofit market increased from 38% in 2001, to 57% in 2003. A complete copy of the evaluation is attached as Appendix B.

4. ONGOING INITIATIVES

Destination Conservation

Destination Conservation (DC) is a K-12 school program involving students, teachers and school facilities management staff.

The program is organized by the Pacific Resource Conservation Society, a BC based not-for-profit group, and offered to school districts. It features energy conservation curricula and support materials for participating teachers and technical assistance to school facilities management staff. Terasen Gas has contributed a portion of the first year operating costs for the program in a number of school districts in prior years. In 2004, Terasen Gas is supporting the Abbotsford School District with funds for 21 schools.

The DC program includes an energy monitoring component which allows school districts to monitor, analyze and report energy usage information. Utilizing software programs such as 'Utility Manager 4.0 Pro' coupled with operator training, Schools are able to report weather-normalized energy savings resulting from implementation of energy efficiency measures. Terasen considers this approach to be a cost-effective means of monitoring program impacts. In addition, DC also supports ongoing monitoring of savings through third party evaluations.

Commercial Energy Utilization Advisory

This program is being offered to larger Rate 3/23 and Rate 5/25 customers by the Terasen Gas Commercial Energy Services group. The offer includes an initial benchmarking consultation and an onsite assessment of natural gas conservation and efficiency opportunities along with recommendations and estimated savings impact. To date there have been 34 completed assessments in 2004, and an expected total of 64 by year end. It is anticipated that 45 customers will commit to implementing the recommended measures resulting in an average annual savings per customer of 594 GJs.

Evaluation report pertaining to this program: BC Gas Commercial DSM Evaluation, R.A. Malatest and Associates Ltd., September 2002

Publications

Terasen Gas publishes a number of brochures and pamphlets to encourage residential customers to adopt energy savings measures and practices. In 2004 the Hot Tips booklet, Heart of your Home (a guide to energy efficient heating systems) and a number of data sheets were updated and published. These booklets and data sheets are available to customers on request. Additional conservation tips and advice have been made available through Homeswest Magazine (a Terasen Gas advertiser-supported publication) and through part sponsorship of the Shell Busey Home Discovery radio show. All publications are available online at the utility web site.

Community Participation

Terasen Gas continues to be an active participant in community-based conservation initiatives (for example, the Community Energy Association) and collaborates with the provincial and federal governments to review energy efficiency standards. In 2004 Terasen Gas participated in the provincial Minister's Advisory Group on building energy performance and supporting committees.

5. SHORT TERM INITIATIVES

Residential Heating System Upgrade Program

An expanded version of programs offered by Terasen Gas in 2002 and 2003, this limited duration Residential Heating System Upgrade program offers financial incentives to residential customers to replace older furnaces and boilers with high efficiency models. The program was initiated September 1, 2004 and terminates December 31, 2004. It is co-sponsored by Natural Resources Canada (NRCan) who is contributing up to $325,000 towards promotional costs and customer incentives.

Residential customers are offered a $250 utility bill credit towards the purchase of an Energy Star qualified high efficiency furnace or boiler--$150 of the contribution is from Terasen Gas and $100 is from NRCan.

Additional supplier-funded incentives ranging from $150 to $1000 in value toward the purchase of 16 brands of Energy Star qualified furnaces and boilers are being promoted by Terasen Gas as part of this program. Most of the major suppliers of high efficiency heating systems in BC are participating—contributing $2,000 towards the direct promotional costs of the campaign and, in some cases, conducting their own independent promotional campaigns.

Early results, to mid-October, suggest the response rate for the 2004 program will exceed that of the 2003 program (2917) and 2002 program (2800).

The program design for the 2004 program estimates the average annual natural gas savings at 13.8 GJ per participant. The 2004 savings calculation reflects a more detailed understanding of the market and program participants: research indicates that participants tended to replace existing heating equipment 4.5 years sooner than non-participants and the standard efficiency furnaces being replaced are approximately 10% more efficient than previously assumed. TGI has also sent two recently removed standard efficiency furnaces for efficiency testing. The GJ savings and corresponding GHG reductions for the program provide a TRC of 1.71 and a reduction of 52 kilotonnes of CO2E.

Evaluation report pertaining to this program: 2003 Residential DSM Campaign Evaluation, Habart & Associates Ltd., August 2004.

New Construction Energy Star Heating Systems

Historically, 95% of the natural gas furnaces installed for new construction in single family dwellings are mid-efficient. We are planning on launching a multi-partner program starting November 2004 that will run through April 30, 2005. It will provide a $600 incentive to builders (depending on partners) for installation of Energy Star space and DHW heating equipment. If the provincial government is able to participate, it could allow an extension of the program to December 31, 2005. Although the program will launch in late 2004, the first applications are not expected until early 2005.

Residential Fireplace Upgrade

This new pilot program launched June 15, 2004 was designed to replace existing inefficient gas log sets with heater-style gas fireplace inserts. The program promoted the new EnerGuide Fireplace Efficiency rating (P.4.1-02) that requires all vented gas fireplaces imported into

Canada or manufactured in Canada and shipped inter-provincially be tested and suitably marked.

Similar to the heating system upgrade program, this fireplace upgrade program included supplier and NRCan participation allowing a $200 bill credit and a $100 manufacturer rebate for the purchase and installation of eligible fireplaces. For homes in which electricity is the primary heating fuel, BC Hydro contributes the $100 utility rebate while Terasen provides the rebate for homes with natural gas as their primary heating fuel.

The program design for this program estimates the average annual natural gas savings at 14.5 GJ per participant – reflecting the improvement of efficiency over a log set (essentially at 0% efficiency) or other low efficiency inserts or free-standing units. Through an RFP process, Terasen has contracted Habart and Associates to conduct a program evaluation at the conclusion of the heating season.

Efficient Boiler Program

Similar in nature to the company's Efficient Boiler Program offered between 1994 and 2000, this initiative provides formula based incentives to purchasers of high efficiency natural gas condensing and "near-condensing" boilers and is available to both the new construction and retrofit markets. It is estimated that 7 commercial customers will have shown interest in the program by December 31 and will therefore be eligible for a future incentive payment attributable to the 2004 program.

Conservation Potential Review

Terasen Gas has begun a Conservation Potential Review (CPR) to provide a minimum 15-year analysis of Demand Side Management (DSM) potential by geographical area identifying the interrelationship between gas and electricity for the residential and commercial sectors. The review will be done in cooperation with BC Hydro and possibly the Alternative Energy Policy Branch of the Ministry of Energy and Mines.

The proposed CPR will be coordinated by an independent third party, Marbek Resource Consultants Ltd., but draw on industry expertise from organisations such as Sheltair, Keen Engineering, Prism Engineering and Willis Energy.

Marbek was selected for this CPR because they were the lead consultant on the 2002 BC Hydro CPR and could leverage developed models, data classifications and arch-types where possible. Sheltair would also be a valuable resource, along with their research on the life cycle costing analysis completed for the *Review of Energy Performance in Buildings* for the province.

Key Deliverables of the CPR

The proposed CPR, leveraging previous studies to reduce costs, will focus on economic screening of natural gas and fuel-independent technologies as well as the combined utility economic analysis of *fuel substitution* (from electric to natural gas). It will examine resource potential at specified milestones, by specific market and end-use, over the forecast period.

The primary outcome will be the identification of reference case forecast change in gas and electric consumption for each of the identified opportunities. The study will also document the assumptions for each of the potential measures so both Terasen Gas and BC Hydro can re-test the opportunities in their respective cost-benefits models.

The deliverables for each of the outcomes are defined in the following table:

Outcome	Content
Analysis of natural gas DSM measures by geographical area	• Stock definition and update of technologies • technology profiles • economic potential • Sensitivity analysis (uncertain fuel costs) • GHG Impact
Analysis of fuel substitution economics by geographical area	• base year calibration • reference case development • impact on peak demand for gas and electric • consider costs of the marginal source of electrical supply based on geographical area • GHG Impacts
DSM Achievable potential	• A set of multi-participant workshops to consider delivery, timing and funding constraints

Need for Joint Fuel Substitution analysis:

The scope of the 2002 BC Hydro CPR did not include an examination of fuel substitution. Terasen Gas believes there is a growing importance for this analysis—there seems to be a market failure in the selection of fuels by market players which could be corrected or improved to the benefit of gas and electric rate payers if the CPR identifies the measures as cost effective. The reasons for the failure could be attributable to some of the following:

- Builders and developers tend to focus on reduction of upfront capital cost versus long run operating costs by the eventual home owner. The capital cost of natural gas may be a barrier. Anecdotal evidence from builders suggests a growing percentage of electric baseboard installations.
- Home buyers and realtors seem to largely ignore the importance of the role of home heating systems in the ongoing operating costs of the home.
- July 1 legislation increases the cost of natural gas water heaters by $130.
- Growth in the popularity of electric fireplaces
- Postage stamp electrical rates do not reflect the varying cost of energy delivery based on service territory.
- Historical electric rates based on heritage supply give misleading price signals to the market that electrical rates may remain near current levels in the long term.

The CPR, however, would focus on the economic benefits: it would examine fuel substitution, identify the benefits of reducing peaking versus flat load, cost per kWh and GJ of the energy saved, and identify the achievable potential of a province wide program.

The total cost of the CPR will be $320,000-$350,000. We are currently in discussions with BC Hydro regarding appropriate cost sharing.

TGI anticipates that the results of the study, available in the spring of 2005, may greatly influence the existing portfolio of DSM measures and, therefore, will advise the Commission once the results are known and multi-year strategy is formulated.

Load Addition Incentive Mechanism

In the 2003 annual review, TGI submitted a framework for a potential load addition incentive mechanism. However, in the context of the aforementioned CPR, an incentive mechanism could more appropriately be developed based on the findings of the fuel-substitution cost-benefit analysis. TGI will therefore, postpone the development of a mechanism until the CPR results are known.

Partnering Opportunities

Terasen Gas has attempted, whenever feasible, to partner with others to leverage utility DSM funds; Natural Resources Canada, BC Hydro, Fortis, and appliance manufacturers have all participated in Terasen programs benefiting customers.

The Alternative Energy Policy Branch of the Ministry of Energy and Mines has applied to the federal "Opportunities Envelope" for $11 million over a three year period for energy efficiency measures of which $3 million pertains to Terasen supported programs. Should the ministry be successful in their application, they will become the primary partner for a number of the Terasen DSM initiatives proposed for 2005.

6. PROPOSED 2005 INITIATIVES

a. Residential Programs

New Construction Energy Star Heating Systems

This proposed program would target the installation of Energy Star qualified natural gas furnaces and boilers in new construction with an incentive payable to residential builders. Possible partners would include NRCan (or provincial support through the Opportunities Envelope) and appliance suppliers. Additional partners may include BC Hydro and Fortis if a high efficiency furnace fan motor incentive is included.

Energy Star Heating System Upgrade

Similar to the upgrade program offered in 2001 – 2003, a utility incentive would be paid to residential customers who upgrade their existing natural gas furnace or boiler to an Energy Star model. Possible partners would include NRCan (or provincial support through the Opportunities Envelope), appliance suppliers, and BC Hydro and Fortis if a furnace fan motor incentive is offered.

Fireplace Upgrade Program

A program evaluation is currently underway for the 2004 program. Based on the results of the evaluation, TGI will tailor a program to either the new construction or retrofit market. In either case, a utility incentive would be paid to participants who select a fireplace with an EnerGuide Fireplace Efficiency rating of 55% or higher. Depending on the results of the 2004 evaluation, upgrade from wood burning fireplaces may also be included. Possible partners would include NRCan (or provincial support through the Opportunities Envelope), appliance suppliers, and BC Hydro and Fortis.

b. Commercial Programs

Commercial Boiler Upgrade

Similar in nature to the company's Efficient Boiler Program offered in 2004, this initiative would provide incentives to purchasers of high efficiency natural gas condensing boilers. Possible partners include NRCan (or provincial support through the Opportunities Envelope) and boiler suppliers.

Commercial Utilization Advisory

The continuation of this program is proposed for 2005 along with an expanded set of web tools to provide commercial customers with comparative natural gas usage information against which their facilities can be benchmarked.

CHBA-BC Project

The Canadian Home Builders Association of BC (CHBA-BC) is bringing together multiple partners to work with builders and contractors to develop energy efficient neighbourhoods. It will facilitate the development of EGH-80[1] community where all houses demonstrate such performance. It assists engagement of all trades with an aim to alleviate barriers to energy efficient new housing design in a systematic fashion, including the first cost barrier. The incentive is still under negotiation by the various partners but will contribute towards the energy savings and emission reductions.

SUMMARY OF 2004 SAVINGS

Program	**Participants**		**Savings (GJ)**	
	Target	Projected	Target	Projected
Residential				
Heating System Upgrade	3000	3000	41,400	41,400
Fireplace Upgrade	1000	325	14,500	4,700
Commercial				
Utilization Advisory	45	45	36,550	26,750
Efficient Boiler Program	15	7	23,500	11,000
Community Based				
Destination Conservation	20	21	4,100	4,300
Other Activities				
Awareness and Education	n/a	n/a	n/a	n/a
Research & Program Design	n/a	n/a	n/a	n/a
	4,080	3,398	**120,050**	**88,150**

[1] NRCan's EnerGuide for Houses (EGH) rating system. A rating of 80 is equivalent to the energy performance of an R-2000 home.

Total Resource Cost Test and DSM Achievement Incentive Status

The Total Resource Cost (TRC) test is a measure of the net benefits of a utility's DSM programs. Terasen Gas calculates overall TRC impact on a 'portfolio' basis, that is, by examining the impact of the combined group of programs for the year.

For the 2004 portfolio (as identified in the table above), the TRC net benefit has been estimated to be $3.4 million with a combined TRC ratio of 2.36.

Greenhouse Gas Reduction

In its residential rebate offers Terasen Gas indicates to customers participating of its intent to record resulting emission reductions as part of the company's Greenhouse Gas Management Program. The net impact of these residential program savings amount to approximately 70 kilotonnes of CO2e (metric tonnes of carbon dioxide equivalent); the net impact for all programs based on current projections is approximately 124 kilotonnes CO_2E.

6. SUMMARY OF COSTS

Program and administration costs as well as customer incentive costs will have remained below allowed levels in 2004. The customer incentives may be lower than anticipated due to lower than expect participation in the fireplace program and a delayed launch of the new construction and efficient boiler programs.

	Allowed ($000)	Projected ($000)
Administration, marketing and research (DRIA)	1,627	1400
Customer Incentives	1,585	630

TAB B-3 DSM STATUS REPORT

ATTACHMENT A

Billing Analysis

2002 Residential Heating System Upgrade Program Evaluation

Prepared for: Terasen Gas

Prepared by:

Habart & Associates Consulting Inc.

July 28, 2004

Table of Contents

Executive Summary

This report is an addendum to "Final Report – 2002 Residential Heating System Upgrade Program Evaluation", October 2003. That report provided the basic summary and evaluation of Terasen's 2002 program, except for the Discrete Choice Analysis to determine attribution, and the billing analysis to determine the energy impact of the program, both of which are covered in this report.

Specifically, this report addresses three issues which are to:

- Use Discrete Choice Techniques (DCT) to further refine the attribution of high efficiency furnace sales to Terasen's program.
- Use billing data to determine the impact of the upgrade program, both in terms of energy and capacity saved and GHG impacts.
- Develop an estimate of the actual AFUE efficiency of standard efficiency furnaces.

A discrete choice model of purchasing a high efficiency furnace was developed. The determinants of purchase were modeled as a function of attitudes towards program participation, energy efficiency and size of the home. Using this model, the net to gross ratio is 80%. That is, 80% of participation is attributed to the program.

As part of the analysis for this report, it was possible to identify a significant group of customers who had upgraded to mid efficiency furnaces as well as the participants who had upgraded to high efficiency furnaces. Billing analysis was undertaken for both groups, and the savings estimates in the report are based on the billing analysis.

The "Final Report – 2002 Residential Heating System Upgrade Program Evaluation" determined a spillover effect in that some of the program participants had been induced by the program to replace their furnace earlier than they would have otherwise done so and for those customers, there was a remaining furnace life of about 4.5 years. Based on the billing analysis and the spillover analysis, net savings are 37.6 TJ per year for the first 4.5 years and 28.1 TJ for the remaining life of the furnace. This equates to a reduction in peak load of 0.22 TJ for the first 4.5 years and 0.16 TJ for the balance, and a reduction in Greenhouse Gas (GHG) of 1.9 kilotonnes of carbon dioxide for the first 4.5 years and 1.4 for the remaining period.

The billing analysis for mid efficiency furnaces and high efficiency furnaces made it possible to infer the efficiency level of furnaces being replaced by the program. It was determined that the equivalent AFUE for furnaces replaced by the program was 70.6%. This estimate can be used in future evaluations to estimate program impact prior to data being available for a billing analysis.

1. Introduction

1.1 Program Overview

Energy conservation programs have two main rationales: environmental and economic. The environmental rationale is that reducing energy consumption can reduce harmful emissions implicated in global warming. Canada has joined most of the international community by signing the Kyoto Protocol in December 1997 and committed itself to reducing greenhouse gas emissions by six percent below the levels in 1990 between 2008 and 2012. While the fate of the Kyoto Protocol itself is uncertain there is still a consensus that reducing GHGs is beneficial. The economic rationale is that reducing energy consumption and peak demand can reduce costs to both utilities and their customers if the marginal cost of energy conservation is less than the marginal cost of new supply. This applies particularly to programs that reduce peak demand and reduce the need for new transmission and distribution facilities that are needed for only a few days per year.

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This incentive was combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers. For the 2002 program, the furnace or boiler had to be purchased from August 1, 2002 to November 30, 2002. Participants received a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada. During this time period 2,785 people participated in the program, almost double the number who had participated in the 2001 program. Of these, 1,474 occurred in the Lower Mainland and 1311 in the Interior (including 100 in the Columbia region).

Program objectives for the Terasen Gas Heating System Upgrade Program included the following: realize residential energy savings; improve residential customer energy awareness; transform the residential furnace market; and assist residential customers in managing energy costs.

1.2 Purpose of the Report

This report is an addendum to "Final Report – 2002 Residential Heating System Upgrade Program Evaluation", October 2003. That report provides the basic summary and evaluation of Terasen's 2002 program, except for the Discrete Choice Analysis to determine attribution, and the billing analysis to determine the energy impact of the program, both of which are covered in this report.

Section 2 provides the study issues and approach used in this report, Section 3 provides the impact results, Section 4 provides the analysis to estimate the AFUE of installed standard efficiency furnaces and Section 5 provides the conclusions.

2. Study Issues and Approach

2.1 Study Issues

As planning for the 2002 Residential Heating System Upgrade Program evaluation progressed, nine critical issues emerged for this study:

- Examine the Efficient Furnace Program, with a view to assessing the rationale for the program.
- Examine the level of customer and trade ally awareness of the furnace technology and the program process.
- Examine the level of customer and trade ally satisfaction with both the furnace technology and the program process.
- Identify and examine program barriers and program opportunities.
- Assess the impact of advertising and promotion activity, including the NRCan funded additional advertising.
- Assess the impact of the program on sales and market share of high efficiency furnaces.
- Assess the impact of the program on prices of high efficiency furnaces.
- Assess the impact of program on energy savings and peak demand due to reduced natural gas consumption.
- Assess the impact of the program on carbon dioxide emissions due to reduced natural gas consumption.

These issues were addressed in the first stage of the program evaluation. However, it was determined that, once billing data became available, three other issues should be address in more depth. These issues are:

- Use Discrete Choice Techniques (DCT) to further refine the attribution of high efficiency furnace sales to Terasen's program.
- Use billing data to determine the impact of the upgrade program, both in terms of energy and capacity saved and GHG impacts.
- Develop an estimate of the actual AFUE efficiency of standard efficiency furnaces.

The question of the AFUE efficiency of standard furnaces is central to determining the actual natural gas savings that can be attributed to the program. Previous evaluations have been done based on NRCan estimates that the AFUE efficiency of a standard efficiency furnace is 60%. However, as noted in the 2001 billing analysis[1], applying these AFUE estimates to the billing data resulted in energy demand for houses that was too low to be reasonable when compared with information on actual household natural gas consumption, and an engineering estimate approach was used determine the impact of that years program. Further analysis suggested that, if the actual AFUE efficiency of a standard furnace was assumed to be about 70%, the billing analysis results would be reasonable when compared with actual household natural gas

[1] Terasen "Evaluation Update – 2001 Winter Bill Saver Program High Efficiency Heating System Offer", December 2003.

consumption.

Subsequent to this conclusion, Terasen staff extended a Conditional Demand Analysis based on the 2002 Residential End Use Study[2] which developed savings estimates for standard, mid and high efficiency furnaces which further supported the hypothesis that the standard furnace efficiency is closer to 70% than 60%.

Therefore one of the objectives of this study was to find a large enough sample of mid efficiency furnaces to accurately determine the difference in consumption between a standard efficiency furnace and a mid efficiency furnace. If a large enough sample is found, then it will be possible to infer the AFUE rating of a standard efficiency furnace using engineering methods.

In addition to the obvious source of mid efficiency furnaces that is found in the non-participants group, it was determined that some potential program participants were rejected as they had installed mid efficiency furnaces and could thus supplement the sample of available mid efficiency furnaces. A billing analysis was done on this group ("AFUE rejects") to determine the reduction in natural gas consumption that results from replacing a standard efficiency furnace with a mid efficiency furnace. Exhibit 2.1 summarizes the evaluation issues, data sources and methods for the present study.

Exhibit 2.1. Evaluation Issues, Data Sources and Methods

Issues	Data sources	Methods
1. Assess the impact of program on unit energy savings due to reduced natural gas consumption	Program data Billing data Weather data 2002 REUS CDA	Weather adjusted billing analysis T-tests Engineering estimates
2. Estimate the share of participant purchases of high efficiency furnaces attributable to the program and the market share of high efficiency furnaces in new furnace purchases	Customer survey - participants - non participants	Discrete choice theory probit regression
3. Determine the installed AFUE of standard efficiency furnaces	Participant billing data Non participant billing data "AFUE reject" billing data	Weather adjusted billing analysis T-tests Engineering estimates

[2] BC Gas "Residential End Use Survey Results", December 2003

2.2 Study Approach

In many program evaluations, program impact is measured as the difference between outcomes for a treatment group (or set of program participants) and a control group (or set of program non-participants). Program impact is then estimated by the "difference of differences" approach where estimated impact is defined as average participant change minus average non-participant change. Here the underlying assumption is that the non-participant change estimates the change that the participants would have experienced on average in the absence of the program[3]. This method works best if there is random assignment to the treatment and control groups, as is often the case in medical and social experiments.

In DSM evaluations random assignment to treatment and control groups is very difficult. For example, participation in the Residential Heating System Upgrade Program is voluntary so that there is potentially an element of self-selection involved. Self-selection in this context means that those who participate in the program may be more likely than average to install energy efficient measures than the average person even in the absence of the program.

There are two main ways of dealing with self-selection: the survey approach and the discrete choice theory approach. In the survey approach, a sample of participants is asked how likely they would have been to install the efficient measure in the absence of the program. Sometimes, responses are weighted to provide an estimate of the free rider rate. However, this method may result in inaccurate estimates because respondents may assume they would have purchased the efficient technology without the program in place, even though this may not be the case. Respondents may also give answers that they think the interviewer wants to hear. Further, respondents are often not conscious of all the factors that lead them to make a specific purchasing decision. Therefore, too much or too little emphasis may be given to the program, when in fact other variables may have played a key role in influencing customer behavior.

Many of these problems can be minimized by using discrete choice analysis (DCA) to estimate program attribution. DCA enables the attribution rate to be estimated based on objective data (explanatory variables), instead of the subjective responses of customers. In DCA, probit or logit regression methods

[3] This methodology, while commonly used in DSM program evaluations does not consider that, in the case of a furnace replacement program, the customer would likely purchase a new furnace in the near future (when the existing unit failed). As the minimum furnace standards were increased in 1995, the new furnace would be more efficient than the existing unit, but not necessarily as efficient as the program induced unit. This issue cannot be addressed purely in a billing analysis as data on the remaining life of the furnace at the time it was replaced is required. This information was available from the survey work done to support the 2002 programs, and is included in this report.

are typically used to estimate the probability of purchasing an efficient technology based on key explanatory variables. Data is collected on customers' observed purchasing behaviour as well as on several explanatory variables. Then probit or logit regression is used to estimate an equation that relates the observed purchasing behaviour to the explanatory variables. This probit or logit equation can then be used to predict the probability that a customer will purchase an efficient technology based on the levels of the explanatory variables for that customer.

For example, in modeling the determinants of participation in the 2002 Residential Heating System Upgrade Program, obviously a discrete choice, the relevant literature suggest that key determinants of the decision to participate might include information about furnace efficiencies, household income and size of the home. This suggests the model shown in (1) which we model using a probit equation, where households are indexed by the subscript i.

(1) program $\text{participation}_i = f(\text{information}_i, \text{income}_i, \text{size}_i)$

The variables are defined as follows:

- participation takes the value "1" for program participants and "0" for program non-participants;
- information takes the value "1" if the respondent agrees that (s)he had adequate information to make an informed decision on choice of furnace and "0" otherwise;
- income is household income in thousands of dollars;
- size is the heated area of the home in thousands of square feet.

In modeling the determinants of installation of a high efficiency furnace, again a discrete choice, the relevant literature suggest that key determinants of the installation decision might include program participation, adequacy of information on furnaces, and size of the home. We also considered income and other variables that proved to degrade the statistical fit of the model. This suggests the model shown in (2) which we model using a probit equation, where households are indexed by the subscript i.

(2) high $\text{install}_i = g(\text{participation}_i, \text{information}_i, \text{income}_i, \text{size}_i)$

The variables are defined as follows:

- high install takes the value "1" for those installing a high efficiency furnace during the program period and "0" otherwise;
- participation is a dummy variable that takes on the value "0" for non-participants and the value "1" for participants;
- information takes the value "1" if the respondent agrees that she had adequate information to make an informed decision on choice of furnace and "0" otherwise;
- income is the household income in thousands of dollars;
- size is the heated area of the home in hundreds of square feet.

The difference of differences approach using billing data is one of the most rigorous methods of estimating gross technology savings. This method helps to control for factors that cause the consumption of participants to change between the pre-program and post-program periods. These factors include changes in energy prices, increased saturation of natural gas using appliances and changes in energy efficiency and energy conservation practices not motivated by the program. Each year Terasen develops a normalized use rate for the residential sector which was used to control for these outside factors. We use the difference of differences approach to estimate gross unit savings for the installation of a high efficiency furnace by region j using (3). We use two regions, the Lower Mainland and the Interior, since energy consumption varies substantially between the two regions.

(3) gross unit saving$_j$ = (participant pre-program consumption$_j$ – participant post-program consumption$_j$) – (pre-program normalized use rate – post-program normalized use rate)

The variables are defined as follows:

- gross unit saving is estimated, weather-normalized annual reduction in GJ in natural gas consumption from installation of a high-efficiency furnace;
- participant pre-program consumption is weather normalized annual consumption in GJ of natural gas in the pre-program period;
- participant post-program consumption weather normalized annual consumption in GJ of natural gas in the post-program period;
- pre-program weather normalized use rate in GJ of natural gas in the pre-program period;
- post-program weather normalized use rate in GJ of natural gas in the post-program period.

We estimate energy savings by region and then aggregate savings across regions using (4). Gross unit savings come from equation (3). The attribution rate is the partial effect on the program participation variable from equation (2), and it is the same for both regions. The number of participants comes from the program database.

To perform the billing analysis, 1,449 of the 2785 participants could be matched with their billing data, and the savings were estimated on this basis.

(4) energy savings$_j$ = Σ_j gross units savings$_j$* attribution rate$_j$ * number of participants$_j$

In estimating peak savings, we assume that heating load on any day is proportional to heating degree days for that day. In the coldest month (January) the average daily heating load is (annual heating load in GJ)*(monthly share of annual heating degree days for January)*(1/31 days). The change in peak day load is then estimated as the change in average daily load for January.

We use data from five zones and calculate the weighted peak day heating load share for January using a representative weather station for each zone and the thirty-year typical meteorological year heating degree-day shares for January. Because of the difference in heating load between the Lower Mainland and the Interior, this is calculated separately for each area. Estimated peak day savings for each area is then weighted peak day heating load share for January multiplied by net savings as shown in (5).

(5) peak day savings = Σ_j weighted peak day heating load share$_j$* energy savings$_j$

We calculate greenhouse gas emissions by regions as the product of energy savings times an emissions factor and then aggregate across regions in (6).

(6) emissions reduction = Σ_j energy savings$_j$* emissions factor$_{j.}$

3. Impact Results

3.1 Program Participation

As noted above, we model the determinants of program participation in the 2002 Residential Heating System Upgrade Program as a function of attitudes towards energy efficiency, household income and size of the home. This equation was estimated using a probit model. Exhibit 3.1 shows the results of the probit regression. For each variable the value of the coefficient, the standard error, the t-statisitic and the partial effect is shown, where the partial effect measures the change in the probability of participation due to a one unit change in the independent or driving variable. Also shown are the chi-squared statistic and the share of outcomes correctly predicted by the model, which are measures of goodness of fit for non-linear equations like the probit. The probit regression was weighted to reflect the fact that the participant sub-sample was over weighted and the non-participant sample was underweighted in the initial data sample. In effect, the participant and non-participant survey data was weighted to better reflect the overall furnace replacement market.

The model fit is good with 75.4% of the outcomes correctly predicted. An increase in information or an increase in household income leads to an increase in the probability of program participation while an increase in household size leads to a decrease in the probability of program participation. Note however that while the coefficients on the other variables are significant at the 5% level or better the coefficient on size is not significant.

Exhibit 3.1. Determinants of Program Participation

	Coefficient	Standard Error	T-statistic	Partial Effect
Constant	-1.74	0.35	-5.00	-0.534
Information	0.87	0.27	3.24	0.265
Income	0.006	0.003	2.22	0.002
Size	-0.004	0.007	-0.53	-0.001
Chi-squared [3 df]	17.8	0.000	-	
Share Correct (%)	75.4	-	-	

We model the determinants of purchase of a high efficiency furnace as a function of program participation, information, household income and size of the home. This equation was estimated using a probit model. Exhibit 3.2 shows the results of the probit regression. As before, the value of the coefficient, the standard error, the t-statistic and the partial effect is shown for each variable, where the partial effect measures the change in the probability of participation due to a one unit change in the independent or driving variable. Also shown are the chi-squared statistic and the share of outcomes correctly predicted by the model, which are measures of goodness of fit for non-linear equations like the probit. Again, the probit regression was weighted to reflect the fact that the participant sub-sample was overweighed and the non-participant sample was underweighted in the initial data collection.

The model fit is good with 75.1% of the outcomes correctly predicted. An increase in program participation, information or home size leads to an increase in the probability of purchase of a high efficiency furnace while an increase in income leads to a decrease in the probability of purchase of a high efficiency furnace. All of the coefficients except that on income have the expected positive signs and are significant at the 5% level or better.

For our purposes, the most important information in the table is the partial effect on the participation variable because this gives us the net to gross ratio. The net to gross ratio is the share of purchases of high efficiency furnaces attributable to the incentive program. The net to gross ratio is 80.0%, which says that about 80% of purchases of high efficiency furnaces under the program are actually attributable to the incentive program. In perhaps more familiar terms, this means that the net effect is 80% and the free rider rate minus the spill over rate is 20% (using the expression, net effect = gross effect minus free rider rate plus spill over rate).

Note that the partial effect on information is 21.4% which indicates that having adequate information has an additional and independent effect on the choice of furnace. While information is available from a number of sources, this reinforces the need to keep information as an important program element.

Exhibit 3.2. Determinants of Furnace Choice

	Coefficient	Standard Error	T-statistic	Partial Effect
Constant	-1.38	0.31	-4.44	-0.509
Participant	2.17	0.29	7.51	0.800
Information	0.58	0.20	2.88	0.214
Income	-0.001	0.003	-0.44	-0.0005
Size	0.038	0.007	5.10	0.014
Chi-squared [3 df]	147.9	0.000	-	-
Share Correct (%)	75.1	-	-	-

3.2 High Efficiency Furnace Unit Energy Savings – Billing Analysis

We use weather normalized billing data to examine pre-participation and post-participation energy consumption for participants and non-participants and calculate the pre/post change. However this change in consumption may not be solely the result of replacing the furnace. Other outside influences such as changes in natural gas prices or rates and household incomes also affect consumption. In order to account for these effects, the year over year change in Terasen's normalized use rate per residential account is used as a proxy to adjust for these externalities.

Exhibit 3.3 summarizes the use rates and year over year changes. The impact of the natural gas rate spikes in 2000 / 2001 can be clearly seen in the decrease in the average use rates.

Exhibit 3.3. Normalized Use Rates

	Use Rate		Year over Year Change	
	Lower Mainland	Interior*	Lower Mainland	Interior
1998	122.8	102.9		
1999	121.9	104.9	-0.9	2.0
2000	116.9	99.7	-5.0	-5.2
2001	105.2	89.8	-11.7	-9.9
2002	113.0	88.7	7.8	-1.1
2003	111.6	89.4	-1.4	0.7

*Weighted average of Columbia and Interior.

Exhibit 3.4 includes weather normalized consumption for Lower Mainland participants, as well as standard errors, sample sizes and t-test for the gross change. The pre/post change in consumption is -21.5 GJ. The t-test is a measure of statistical significance. Since a t-value of 2.0 is significant at the 95% confidence level, the magnitude of the change with its t-value of 30.7 is statistically significant. The gross change in consumption is then adjusted by the change in normalized use rate to determine a net reduction of 20.1 GJ.

Exhibit 3.4. Lower Mainland Participant Savings (High Efficiency Furnaces)

	Consumption (GJ)	Standard Error (GJ)	Sample Size (units)	T-test for Change
Pre	122.5	2.35	740	
Post	101.0	2.03		
Change	-21.5	0.70		30.7
Adjust.	1.4			
Net	20.1			

Exhibit 3.5 includes weather normalized consumption for Interior participants, as well as standard errors, sample sizes and t-test for the change. The pre/post change in consumption is -21.9 GJ. Since a t-value of 2.0 is significant at the 95% confidence level, the magnitude of the change with its t-value of 34.8 is statistically significant. Again this is adjusted by the change in normalized use rate to determine a net reduction of 22.6 GJ.

Exhibit 3.5. Interior Participant Savings (High Efficiency Furnaces)

	Consumption (GJ)	Standard Error (GJ)	Sample Size (units)	T-Test for Change
Pre	112.0	1.36	708	
Post	90.1	1.22		
Change	-21.9	0.63		34.8
Adjust.	-0.7			
Net	-22.6			

3.3 Mid Efficiency Furnace Unit Energy Savings – Billing Analysis

We also use weather normalized billing data to examine pre-participation and post-participation energy consumption for non-participants and calculate the pre/post change. Exhibit 3.6 includes weather normalized consumption for Lower Mainland participants, as well as standard errors, sample sizes and t-test for the change. The gross unit pre/post change in consumption is -10.5 GJ. In this case the t-value is greater than 2.0 and the change is significant at the 95% confidence level. This is adjusted by the change in normalized use rate to determine a net reduction of 9.1 GJ.

Exhibit 3.6. Lower Mainland Non-participant Savings (Mid Efficiency Furnaces)

	Consumption (GJ)	Standard Error (GJ)	Sample Size (units)	T-Test for Change
Pre	112.7	4.7	64	
Post	102.7	4.5		
Change	-10.5	2.4		4.4
Adjust.	1.4			
Net	-9.1			

Exhibit 3.7 includes weather normalized consumption for Interior non-participants, as well as standard errors, sample sizes and t-test for the change. The gross unit pre/post change in consumption is -7.4 GJ. In this case the t-value is greater than 2.0 the change is significant at about the 95% confidence level. This is adjusted by the change in normalized use rate to determine a net reduction of 8.1 GJ.

Exhibit 3.7. Interior Non-participant Savings (Mid Efficiency Furnaces)

	Consumption (GJ)	Standard Error (GJ)	Sample Size (units)	T-Test for Change
Pre	96.3	6.0	35	
Post	88.8	5.6		
Change	-7.4	2.4		3.1
Adjust.	-0.7			
Net	-8.1			

3.4 Gross and Net Energy Savings – Billing Analysis

The previous analysis will now permit determining the energy savings between a mid efficiency furnace and a high efficiency furnace. Exhibit 3.8 summarizes this data.

Exhibit 3.8. Energy Savings by Furnace Efficiency Level

	Participants by Region	Standard to High Efficiency Furnace (GJ)	Standard To Mid Efficiency Furnace (GJ)	Mid to High Efficiency Furnace (GJ)
Lower Mainland	1,474	20.1	9.1	11.0
Interior	1,311	22.6	8.1	14.5
Weighted Average	2,785	21.3	8.6	12.6

As part of the initial evaluation in 2003, it was determined that the impact should be calculated in two steps. For all participants, it was determined that the impact was the difference in consumption between a mid and high efficiency furnace, as adjusted by the "net to gross" ratio to remove the effect of free riders. In addition there is a "spill over" benefit to the extent that the program encouraged people to replace their furnace earlier than they would otherwise have done. The market research determined that 1,108 participants had been influenced to replace their furnaces earlier by the program, and the trade ally survey determined that these furnaces had, on average, a remaining life of 4.5 year.

To estimate energy savings, unit savings are multiplied by the number of participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio. Estimated net savings based on the billing analysis are 37.6 TJ per year for the first 4.5 years and then 28.1 for the remaining 20.5 years, based on an expected furnace life of 25 years.

Exhibit 3.9. Energy Savings – Billing Analysis

	Unit savings (GJ)	Gross participants (000)	Gross savings (TJ)	Net to gross ratio	Net savings (TJ)
Direct	12.6	2,785	35.09	0.80	28.07
Spill over	8.6	1,108	9.53	1.00	9.53
Annual – first 4.5 years					37.60
Annual – subsequent years					28.07

By way of comparison, the initial evaluation estimated the savings at 36.85 TJ for the first 4.5 years and 15.89 for subsequent years.

3.5 Peak Savings

In estimating peak savings, based on the engineering estimates above, we assume that heating load on any day is proportional to heating degree days for that day, so that in the coldest month (January) the average daily heating load is (annual heating load in GJ)*(monthly share of annual heating degree days for January)*(1/31 days). The change in peak day load is then estimated as the change in average daily load for January.

The following exhibit calculates the weighted peak day heating load share for January using a representative weather station for each zone and the thirty-year typical meteorological year heating degree-day shares for January. Because of the difference in heating load between the Lower Mainland and the Interior, this is calculated separately for each area. Estimated peak day savings for each area is then weighted peak day heating load share for January multiplied by net savings. Exhibit 3.11 shows peak day savings are 0.216 TJ for the first 4.5 years after the program and 0.161 TJ for the remaining 20.5 years.

Exhibit 3.10. Peak Contribution by Zone

Zone	Weather Station	Zone customer share	Area Customer Share	Peak day heating load share	Weighted peak day heating load share
Zone 1	Vancouver	0.244	0.350	0.00501	0.00175
Zone 2	Burnaby	0.173	0.248	0.00511	0.00127
Zone 3	Surrey	0.280	0.402	0.00510	0.00205
	Lower Mainland	0.697	1.000		0.00507
Zone 4	Kamloops	0.117	0.386	0.00625	0.00241
Zone 5	Cranbrook	0.186	0.614	0.00667	0.00410
	Interior	0.303	1.000		0.00651
Total		1.000			

Exhibit 3.11. Peak Day Savings

Weather Station	Weighted peak day heating load share	First 4.5 years		Subsequent years	
		Net Energy savings (TJ)	Peak day savings (TJ)	Net Energy savings (TJ)	Peak day savings (TJ)
Lower Mainland	0.00507	19.90	0.1009	14.86	0.753
Interior	0.00651	17.70	0.1152	13.21	0.860
		37.60	0.2161	28.07	0.1613

3.6 Carbon Dioxide Emissions Reduction

Using an emissions factor of 50 tonnes of carbon dioxide per terajoule or 0.050 kilotonnes per terajoule yields an emissions reduction or carbon dioxide savings total of 1.72 kilotonnes as shown below.

Exhibit 3.12. Carbon Dioxide Emissions Reductions

	Net savings (TJ)	CO_2 Factor	CO_2 reductions (ktonnes)
Direct	28.07	0.05	1.40
Spill over	9.53	0.05	0.48
Total – first 4.5 years	37.60	0.05	1.88
Total – subsequent years	28.07	0.05	1.40

4. AFUE Estimation (Standard Furnace)

Given the information on the difference in consumption between the three levels of furnace efficiency, and assuming the regulated AFUE efficiency for mid efficiency furnaces at 78% and the average high efficiency furnaces at 92%, it is possible to estimate the equivalent AFUE level for furnaces replaced during this program (assumed to be standard efficiency) with the following approach.

The key assumption is that, for any given house, the heat output of furnaces with varying efficiencies are the same (since the heating load that needs to be met is the same), but the natural gas consumption will vary in direct proportion to the AFUE rating of the furnace. The relative efficiency of the mid and high efficiency furnace and the difference in consumption are used to determine the consumption of a high efficiency furnace. Then the heat load of the house is calculated from the consumption and AFUE of the high efficiency furnace. The natural gas consumption of the standard efficiency furnace is estimated by adding the consumption of the high efficiency furnace and the difference in consumption between a standard and a high efficiency furnace as determined by the billing analysis. Then the AFUE rating for the standard efficiency furnace is the ratio of consumption to heat output. Appendix C contains the detailed calculation.

By this method, it was estimated that the efficiency of the average furnace replaced by this program was 70.6%. The estimation of the AFUE for a standard efficiency furnace can be used in future year's evaluations to estimate the impact of the program prior to the billing analysis being completed.

5. Conclusions

Conclusion 1. Gross Measure Unit Savings. Weather normalized billing data was used to examine pre-participation and post-participation energy consumption for participants. Terasen's Normalized Use Rates, which reflect year over year changes in residential consumption, were used to adjust for changes in usage outside of the program. The net change for the Lower Mainland was -20.1 GJ per year while the net change for the Interior was -22.6 GJ per year. The weighted average for the Terasen system is -21.3 GJ per year.

A billing analysis was also conducted on a group of customers who had applied for the incentive but were rejected as they had installed mid efficiency furnaces. This sample provided data on the change in natural gas consumption between a standard and mid efficiency furnace. The net change for the Lower Mainland was -9.1 GJ per year while the net change for the Interior was -8.1 GJ per year. The weighted average for the Terasen system is -8.6 GJ per year.

Conclusion 2. Market Effects Due to the Program. We model the determinants of purchasing a high efficiency furnace as a function of attitudes towards program participation, energy efficiency, and size of the home using a probit model. Using the model, the net to gross ratio is 80.0%, which says that about 80.0% of purchases of high efficiency furnaces under the program are actually attributable to the program. In other words, this means that the net effect is 80.0% and the free rider rate minus the spill over rate is 20.0% (using the expression, net effect = gross effect minus free rider rate plus spill over rate).

Conclusion 3. Impact on Energy Consumption. To estimate energy savings, unit savings are multiplied by the number of participants by area to get gross savings. Net savings are then equal to gross savings times the net to gross ratio. Spillover was estimated as the impact of bring forward the replacement of the furnace by an average of 4.5 years. Based on the billing analysis and spillover analysis, net savings are 37.60 TJ per year for the first 4.5 years, and 28.07 GJ per year for the remaining 20.5 years, assuming a furnace life of 25 years.

Conclusion 4. Impact on Peak. In estimating peak savings, we assume that heating load on any day is proportional to heating degree days for that day, so that in the coldest month (January) the average daily heating load is (annual heating load in GJ)*(monthly share of annual heating degree days for January)*(1/31 days). The change in peak day load is then estimated as the change in average daily load for January. Based on the engineering estimates, peak day savings are 0.216 TJ per year for the first 4.5 years, and 0.161 TJ per year for the remaining 20.5 years, assuming a furnace life of 25 years.

Conclusion 5. Impact of the Program on Greenhouse Gas Emissions. Using the engineering estimates and an emissions factor of 50 tonnes of carbon dioxide per terajoule or 0.050 kilotonnes per terajoule yields an emissions reduction or carbon dioxide savings total of 1.88 kilotonnes per year for the first

4.5 years, and 1.4 kilotonnes per year for the remaining 20.5 years, assuming a furnace life of 25 years.

Conclusion 6. Estimated AFUE of Replaced Furnace. Based on the billing data for mid and high efficiency furnaces and the minimum efficiency AFUE levels of 78% for mid efficiency furnaces and 92% for high efficiency furnaces, it was estimated that the AFUE of the replacement furnace (assumed to be a standard efficiency unit) was 70.6%.

Appendix A – Weather Normalization Methodology

The weather normalization of the billing data used for this project was developed by Terasen Gas. This description of the weather normalization process was provided by Mr. Lee Robson of Terasen Load Forecast Group.

When normalizing consumption with respect to weather for Rate 1 customers, the following methodology is followed:

1. Obtain consumption history, ensuring at least twelve months consumption is available per period (period being "pre" and "post" installation periods). This provides a number of read dates, consumption and the number of days over which consumption occurred. The consumption figures are converted so that they provide an average daily consumption (total consumption / read days = average consumption).

2. Obtain the HDD's (Heating Degree Days – both using a 13 degree and 18 degree heating day) covering the entire period in question. The average HDD's (both 13 and 18) are matched to the dates in (1), to provide both average consumption and average HDD's.

3. Run the following regression model:

   AvgConsumption = Alpha + (Beta1 X AvgHDD13) + (Beta2 X AvgHDD18) + Error

4. The parameters Alpha, Beta1, and Beta2 from the above regression are then applied to the total HDD's (13 and 18) that would be experience during a "normal" year (which is basically the average of the HDD's over the past 10 years), and this results in a "normalized consumption". The actual formula applied to the parameters calculated in (3) is:

   Normal Consumption = (365 X Alpha) + (TotalHDD13 X Beta1) + (TotalHDD18 X Beta2).

Appendix B – Billing Data Screening

This description of the billing data screening process was provided by Mr. Lee Robson of Terasen Load Forecast Group.

For each premise, consumption information is obtained for a period of 500 days both prior to and after the installation date.

Using the bi-monthly meter reads (and associated consumption), the average daily consumption per meter read is determined. The average daily HDD13 and HDD18 for that same period is also determined. Then run the following regression model is run:

Average Daily Consumption = B0 + (B1 X HDD13) + (B2 X HDD18)

The total HDD13's and HDD18's during a "normal" year (basically the average of the past ten years) are determined and a normalized annual consumption is calculated by:

Normal Consumption = (365 X B0) + (TotalHDD13's X B1) + (TotalHDD18's X B2)

The above calculations are performed on the "pre" and "post" consumption separately.

The following elimination criteria are then applied which provides the finalized list:

1. Only keep those customers that have been in the same premise for at least one year prior to and after the installation date.
    - As different customers have different consumption requirements, a bias would be introduce bias if this screen wasn't used.

2. Only keep those customers where the regressions give an R-Square value > 75%
    - This ensures the model (consumption as a function of heating degree days, both 13 and 18) is a good fit – a value of 75% or greater implies that ¾ of the variation in the model is explained by the model.

3. Only keep those customers where the heatslope coefficient is positive (HDD18)
    - As customers should consume more gas as the heating degree days increase, this screen removes those customers that show less consumption as heating degree days increase.

4. Only keep those customers who have an actual annual consumption > 30GJ

- The average heating load for a Terasen customer is 68 GJ (2002 REUS). This screen eliminates customers who would appear to be using natural gas only for non-heating uses or as secondary heat.

5. Only keep those customers where the EDF (Error Degrees of Freedom) > 3 (which means we have at least five meter reads for that customer)
   - This filters out suspect meter reads, which are meter reads where the transaction period refers back to a date prior to the last read date output (ie. The read date less the corresponding read days is before the last read date). Meter reads are also filtered out where the consumption is zero. For at least one years' worth of consumption, there should be at least 6 meter reads – therefore this screen basically ensures we haven't skipped over more than one meter read.

6. Only keep those customers where the weather effect is less than 2 standard deviations away from the average weather effect. The weather effect is defined as:

Weather Effect = (Normal Consumption – Actual Consumption) / Actual Consumption

   - This basically filters out the outliers – since 96% of all data is within two standard deviations of the mean, this simply eliminates those with abnormally large weather effects.

The final step is to match those customers in the "pre" analysis with those in the "post" analysis

Appendix C – AFUE Estimation (Detailed Calculation)

Given the information on the difference in consumption between the three levels of furnace efficiency, and assuming the regulated AFUE efficiency for mid efficiency furnaces at 78% and the average high efficiency furnaces at 92%, it is possible to estimate the equivalent AFUE level for standard efficiency furnaces with the following equations.

(1)	$C_S - C_H = 21.3$ GJ	GJ reduction between furnace eff. levels
(2)	$C_S - C_M = 8.6$ GJ	
(3)	$C_M - C_H = 12.6$ GJ	
(4)	$C_M = 12.6 - C_H$	Restate statement (3) in terms of C_M
(5)	$.92\ C_H = .78\ C_M$	Output heat of the two furnaces is equal
(6)	$C_M = .92 / .78C_H$	Restate statement (5) in terms of C_M
(7)	$12.6 + C_H = .92 / .78C_H$	Combine statements (4) and (6)
(8)	$12.6 = .92 / .78C_H - C_H$	Simplify expression
(9)	$12.6 = .14 /.78\ C_H$	
(10)	$C_H = 12.6 * .78 / .14$	Solve for C_H
(11)	$C_H = 70.2$ GJ	Consumption of a high efficiency furnace
(12)	$E_D = 70.2 * .92$	Heat demand for house (92% AFUE)
(13)	$E_D = 64.6$	
(14)	$C_S = 70.2 + 21.3$ GJ	Std. consumption is High cons. + difference
(15)	$C_S = 91.5$ GJ	in consumption between Std. and High
(16)	AFUE Std = 64.6 / 91.5	AFUE is ratio of energy output to energy
(17)	AFUE Std = 70.6%	input

Where:
C_S = Energy Consumption (std. efficiency)
C_M = Energy Consumption (mid efficiency)
C_H = Energy Consumption (mid efficiency)
E_D = Energy Demand for House

The estimation of the AFUE for a standard efficiency furnace can be used in future year's evaluations to estimate the impact of the program prior to the billing analysis being completed.

TAB B-3 DSM STATUS REPORT

ATTACHMENT B

Final Report

Impact of Terasen Gas / Energy Star Heating System Upgrade (2003) Program

Prepared for: Terasen Gas

Prepared by:

Habart & Associates Consulting Inc.

August 2004

Table of Contents

i. Executive Summary

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This incentive was combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers. For the 2003 program, the furnace or boiler had to be purchased from September 1, 2003 to December 15, 2003. Participants received a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada. The program was expanded from the previous year to include a financing option and an additional $150 rebate for furnaces including a variable speed blower motor. During this time period 2,915 people participated in the program, up from 2,785 in the 2002 program.

The objective of this study was to provide an impact, process and market evaluation of the 2003 program and build on the evaluation experience of the previous two year's programs. Following a review of the 2002 program evaluation, fourteen evaluation areas emerged:

- Determine customer and trade ally satisfaction with the program.
- Assess impact of marketing / advertising of program.
- Assess effectiveness of financing vs. rebates as incentives.
- Determine installed prices of mid and high efficiency furnaces (HEF).
- Assess program impact on sales of high efficiency furnaces.
- Assess program impact on sales of variable speed blower motors (VSM).
- Determine the usage of furnace blowers before and after the furnace replacement.
- Assess change in the use of secondary heating after installation of HEF furnace.
- Examine determinants of HEF program participation.
- Examine determinants of VSM incentive participation.
- Provide discrete choice based estimates of energy savings.
- Provide discrete choice based estimates of carbon dioxide reductions.
- Determine status of market transformation in the BC furnace market.
- Determine pre/post change in weather adjusted natural gas consumption.

Given the wide scope of these evaluation areas, a number of data sources and methods were used in this study. Telephone interviews were conducted with approximately 100 participants and 100 non-participants[1] as well as 40 trade allies who had participated in the program. The survey data was combined with information from Terasen Gas' program data bases to provide answers to the fourteen evaluation areas noted above. In this report, the impact numbers were developed based on engineering estimates. Once sufficient billing data is available, the impact estimates will be re-developed based on the billing data.

[1] It should be noted that, for the purpose of this study, non-participants were defined as people who purchased a furnace, but who did not participate in the Terasen Gas program as this approach was felt to provide more valuable information on the state of the furnace market than using a general population recruit.

This analysis will be done in the fall of 2005.

The conclusions of the study are as follows:

Conclusion 1: customer and trade ally satisfaction with the program:

Maintaining high levels of customer satisfaction is a key concern of program management and staff. Satisfaction with a variety of program components was rated on a five-point scale where one is not at all satisfied and five is very satisfied. Participants reported satisfaction levels averaging 3.8 or more for application procedures, information on the rebate, information abut efficient furnaces and types of furnaces eligible for the rebate. Lower levels of satisfaction were expressed for the time period of the program and the amount of the rebate, but these are 3.7 and still quite positive. Trade Allies reported satisfaction of 3.8 or higher for the amount of the rebate, types of furnaces eligible for a rebate, information on the rebate and application processing. The program continues to achieve high levels of customer and trade ally satisfaction.

Conclusion 2: impact of marketing / advertising of program:

Advertising and promotional activities are a key means of increasing program awareness and participation. For participants and non-participants, the main sources of awareness are the insert in the Terasen Gas bill, the heating contractor and word of mouth. However, with the exception of bill inserts, these sources of awareness are all quoted at lower levels by non-participants. Compared with the 2002 evaluation, awareness of the program by non-participants has declined from about 41% to 31%. At the same time it appears that the demographics of non-participants has also changed. In 2003 over 68% of the non-participants were age 55 and over whereas in 2002 only 50% fell into this category. This shift in demographics may indicate a need for different strategies to reach the older age groups. A second possible cause for the decline in awareness is that in 2002, the Furnace Tune-up program had 45,000 participants which may have generated broader awareness of all Terasen programs.

Conclusion 3: effectiveness of financing vs rebates as incentives:

The 2003 program included a finance option for the first time. Analysis of program records indicates that only 211 of the 2,915 participants, or about 7%, took advantage of the option. However 57% of these people, or 120 participants indicated that, without the financing option, they would not have purchased a new furnace at this time. Therefore it can be concluded that the finance option increased the program sales by about 4%, or about the total increase in sales between 2002 and 2003.

Conclusion 4: installed prices of mid and high efficiency furnaces (HEF):

One of the indicators of market transformation is the reduction of prices, or at least of price premiums, for energy efficient products to the consumer. While there is some indication of a general price rise for all furnaces between 2002 and 2003, there also appears to have been a decrease in the incremental installed price of a high efficiency furnace relative to a mid efficiency furnace. The incremental price has dropped from $877 to $608, or about 30%. This is the equivalent of a reduction in payback period from 5.6 years in 2002 to 3.9 years in 2003.

Conclusion 5: program impact on sales of high efficiency furnaces:

Three approaches to determining program attribution were considered: (1) responses to customer survey questions; (2) responses to trade ally survey questions, and (3) the Discrete Choice approach. These different approaches provided an attribution of 57% from the Customer survey, 76% from the Trade Ally survey and 72.3% from the Discrete Choice analysis. The Discrete Choice estimate was used as this approach is typically less biased and better reflects the impact of the overall program rather than just the incentive component.

Conclusion 6: program impact on sales of variable speed blower motors (VSM):

Impact of the program on sales of VSMs is less clear than for high efficiency furnaces. Both Customers and Trade Allies were asked about the importance of the program in their choice of furnace with VSM. The Customers' survey indicated an attribution rate of 61% to the program while the Trade Allies indicated a lower rate of 50%. However a comparison of adoption rates between participants and non-participants showed an increase in sales to participants of only 41%.

Conclusion 7: usage of furnace blowers before and after the furnace replacement:

Customers and Trade Allies were queried about the use of their furnace blowers before and after the installation of the new furnace. Analysis of the Customer data shows that people who were making use of the furnaces to provide various levels of ventilation (ie: not just when the system is providing heating or cooling) were more likely to buy a furnace with a VSM. Data on blower usage after the furnace was installed shows that usage of the blower only when providing heating or cooling declined from 73% to 64% with more intensive uses of the blower increasing by a similar amount. However most of this increased blower usage is going to furnaces with VSMs. For example, when comparing blower usage before the furnace installation with just those people who installed VSMs, the usage when only providing heating or cooling declines from 73% to 55%. The Trade Ally data confirms these trends, but shows an even stronger shift to continuous ventilation.

Conclusion 8: change in the use of secondary heating after installation of HEF furnace:

The Customer survey determined that 42% of participants decreased their use of secondary space heating after installing the new furnace while only 5% increased their usage. If the space heating fuel is other than natural gas, a reduction in secondary heating will increase the load on the furnace. However if the secondary heating fuel is natural gas, and the secondary heating source is less efficient that the furnace, a reduction in secondary heating will increase the natural gas savings as the load is picked up by the more efficient furnace. The potential impact from the reduction in secondary heating after the installation of the high efficiency furnace appears small, in the order of -0.7 GJ per year. Given the significant assumptions required for this analysis, it was concluded not to include any impact from secondary heating in the program impacts.

Conclusion 9: determinants of HEF program participation:

The discrete choice analysis for the overall furnace program found that the primary determinants of program participation were: consumption of natural gas; importance of energy efficiency and importance of costs. This is also reflected by survey questions on the importance of various influencers on heating system choice (measured on a 5 point scale) which included: energy efficiency (4.5); comfort (4.4); and operating cost (4.3).

Conclusion 10: determinants of VSM incentive participation:

The primary drivers for participation in the VSM incentive component of the program were: energy efficiency (49%); contractor recommendation (23%); quieter operation (10%) and wanted continuous ventilation (10%).

Conclusion 11: discrete choice based estimates of energy savings:

To estimate energy savings, unit savings are multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio. Estimated net savings are 37.4TJ for the first 5.4 years and 26.6TJ for subsequent years. Estimated peak day savings are the weighted peak day heating load share for January multiplied by net savings. Estimated peak day savings are 0.20TJ for the first 5.4 years and then 0.15TJ for subsequent years.

Conclusion 12: discrete choice based estimates of carbon dioxide reductions

Using an emissions factor of 50 tonnes of carbon dioxide per terajoule yields an emissions reduction or carbon dioxide savings of 1.87 kilotonnes of carbon dioxide for the first 5.4 years of the program and 1.33 kilotonnes of carbon dioxide for subsequent years of the program.

Conclusion 13: status of market transformation in the BC furnace market:

Two indicators of market transformation are considered in this evaluation, changes in market share of high efficiency furnaces over time and changes in customer payback, with increasing market share and improving payback being considered as indicators of market transformation.

- The market share of high efficiency furnaces in the retrofit segment has increased from about 38% in 2001 to about 57% in

2003 while the estimate of the overall furnace market served by Trade Allies included in the study has increased from 29% to about 52%.

- Based on typical furnace prices provided by the Trade Allies, it appears that the incremental cost of installing an high efficiency furnace relative to a mid efficiency furnace has dropped between 2002 and 2003, with a reduction in payback period to the customer dropping from 5.6 years to 3.9 years.

These indicators suggest that the program is making substantial progress in transforming the market for furnaces in B.C.

1. Introduction

1.1 Program Overview

Energy conservation programs have two main rationales: environmental and economic.

- The environmental rationale is that reducing energy consumption can reduce harmful emissions implicated in global warming. Canada has joined most of the international community by signing the Kyoto Protocol in December 1997 and committed itself to reducing greenhouse gas emissions by six percent below the levels in 1990 between 2008 and 2012. While the fate of the Kyoto Protocol itself is uncertain there is still a consensus that reducing GHGs is beneficial.
- The economic rationale is that reducing energy consumption and peak demand can reduce costs to both utilities and their customers if the marginal cost of energy conservation is less than the marginal cost of new supply.

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. In 2003, a financing option was added to the previous $ 300 grant. Also, an additional $ 150 incentive was provided for customers who chose furnace models with a variable speed blower motor (VSM). These incentives were combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers.

For the 2003 program, the furnace or boiler had to be purchased from September 1, 2003 to December 15, 2003. Participants received a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada. During this time period 2,915 people participated in the program, up from 2,785 who had participated in the 2002 program. Of the participants, 2704 received the $ 300 grant while 211 chose financing. One thousand, six hundred and twelve (1,612) purchased furnaces with variable speed motors (VSM) for the furnace blower, 1474 in BC Hydro's service area and 138 in Aquila's (now Fortis BC's) service territory. Fifty-one percent of the participants were from the Lower Mainland, while the remainder was from the Interior (including the Columbia area).

Program objectives for the Terasen Gas Heating System Upgrade Program included the following: realize residential energy savings; improve residential customer energy awareness; transform the residential furnace market; and assist residential customers in managing energy costs.

1.2 Outline of the Report

This report provides a process, market and impact evaluation of the Heating System Upgrade Program. Section 1 provides an overview of the Heating System Upgrade Program and of this study. Section 2 discusses the study objectives, approach, evaluation areas and methods used. Section 3 describes the key program elements including program design, program marketing and program delivery. Section 4 presents the results of the consumer survey. Section 5 presents the results of the trade ally survey. Section 6 summarizes the impact results including the effect of the program on furnace sales and market share, furnace prices, energy savings and carbon dioxide emissions. Section 7 provides the conclusions of the study.

2. Objectives and Approach

2.1 Study Objectives and Approach

Governments, regulators and utilities are looking to incentive programs to deliver cost effective energy savings and reduce greenhouse gas emissions. Evaluation of space heating and appliance incentive programs leads to analysis of four key objectives: first, to what extent does the incentive program result in incremental or additional purchases of the efficient measure; second, what impact does the incentive program have on prices for the technology paid in the market; third, how large are the energy savings that can validly be attributed to the program; fourth, what are the program impacts on GHG emissions?

In typical program evaluations, considerable effort is placed on obtaining accurate estimates of gross technology savings, but less attention is given to market effects including price impacts of incentives, determinants of technology adoption, free rider analysis and technology costs. In this study we have provided Terasen Gas with a more useful and credible analysis by collecting valid information on market effects including prices and sales through detailed telephone surveys, and then combining this information with existing program data and engineering algorithms to undertake rigorous analysis of all evaluation areas.

The evaluation design includes a second phase of impact evaluation based on the analysis of billing consumption once the furnaces have been installed for a full heating season. It is anticipated that this work will be undertaken during the summer of 2005.

2.2 Study Areas and Methods

Following the initial team discussions and review of the 2002 program evaluation, fourteen critical study areas emerged for this study:

- Determine customer and trade ally satisfaction with the program.
- Assess impact of marketing / advertising of program.
- Assess effectiveness of financing vs rebates as incentives.
- Determine installed prices of mid and high efficiency furnaces (HEF).
- Assess program impact on sales of high efficiency furnaces.
- Assess program impact on sales of variable speed blower motors (VSM).
- Determine the usage of furnace blowers before and after the furnace replacement.
- Assess change in the use of secondary heating after installation of HEF furnace.
- Examine determinants of HEF program participation.
- Examine determinants of VSM incentive participation.
- Provide discrete choice based estimates of energy savings.
- Provide discrete choice based estimates of carbon dioxide reductions.
- Determine status of market transformation in the BC furnace market.
- Determine pre/post change in weather adjusted natural gas consumption.

Given the wide scope of these study areas, a number of data sources and methods were used in this study. An outline of the evaluation areas, data sources and methods is shown in Exhibit 2.2.1.

This evaluation will be done in two Phases. The first phase includes the market research and analysis required to meet the fourteen objectives noted above, although the substantive work for the last issue will constitute the second phase. The evaluation included program participants from the 2003 programs and non-participants who purchased a furnace in 2003 or 2004, but did not participate in the program. The survey work was done between May 25 and June 6 of 2003. The completion rate for participants was 36%, while the completion rate for non-participants (defined as people who had purchased a furnace in 2002 or 2003, but who had not participated in the Terasen program) was 2.8%. The lower completion rate for non-participants reflects the absence of contact information for these households which meant that a random telephone survey was required. In each year, about 2.7% of the population purchases a replacement furnace.

Phase 1 includes the data collection and an initial impact analysis based on engineering estimates and the results of a discrete choice analysis. However, this approach does not allow the savings estimates to be based on actual consumption, or billing history, as customers have not had the new heating equipment installed for a full heating season. Once the billing history is available, we will complete Phase 2 and re-calculate the energy impact for the program based on the actual billing history. For the 2003 participants, the billing history is expected to be available by summer 2005.

Exhibit 2.2.1. Evaluation Areas, Data Sources and Methods

Evaluation Issue	Data Sources	Methods
Phase 1.		
1. Determine customer / trade ally preferences for future programs.	Customer survey Trade ally survey	Cross tabulations
2. Assess impact of marketing / advertising of program.	Customer survey Trade ally survey	Cross tabulations
3. Assess effectiveness of financing vs. rebates as incentive.	Customer survey Trade ally survey	Cross tabulations
4. Determine installed prices of mid and high efficiency furnaces	Customer survey	Pre/post comparisons
5. Assess program impact on sales of high efficiency furnace.	Customer survey	Cross tabulations
6. Assess program impact on sales of variable speed blower motors.	Customer survey	Cross tabulations
7. Determine usage of furnace blowers before and after furnace replacement.	Customer survey Trade ally survey	Cross tabulations
8. Assess installation of HEF furnace on the use of secondary heating.	Customer survey	Cross tabulations
9. Examine determinants of HEF furnace program participation.	Customer survey	Discrete choice modelling
10. Examine determinants of VSM motor rebate participation.	Customer survey	Discrete choice modelling Cross tabulations
11. Provide discrete choice based estimates of program impact to determine energy savings	Program records Previous research Customer survey	Engineering algorithms
12. Provide discrete choice based estimates of program impact to determine carbon dioxide reductions.	Program records Previous research Customer survey	Engineering algorithms
13. Determine status of furnace market transformation in B.C.	Customer survey Trade ally survey	Cross tabulations
Phase 2		
14. Determine pre/post change in weather adjusted natural gas consumption	Billing records Weather files	Weather adjusted billing analysis
14a. Revise discrete choice based estimates of program impact to determine energy savings	Billing Analysis Previous research	Engineering algorithms
14b. Revise discrete choice based estimates of program impact to determine carbon dioxide reductions.	Billing Analysis Previous research	Engineering algorithms

The customer survey collected information on the following:

- Customer awareness of the program.
- Customer satisfaction with the program and its components.

- Customer incentive preference
- Customer demographic characteristics.
- Furnace blower motor characteristics, preferences and usage.
- Furnace characteristics including age, capacity and price.
- Housing characteristics including size and fuel types.
- Program barriers and opportunities.
- Program design issues.

The trade ally survey collected information on the following:

- Trade ally awareness.
- Trade ally satisfaction with the program and its components.
- Trade ally firm characteristics.
- Characteristics of furnaces sold including efficiency level, fan usage and price as well as market characteristics.
- Program barriers and opportunities.
- Program design issues.

It was determined that telephone surveys would be the best way to collect timely information while minimizing the response burden. The surveys were designed to provide as much comparability between survey groups as possible. This maximized the number of issues for which responses could be compared across the groups. The draft survey instrument was pre-tested and modified to improve several questions and the questionnaire flow.

Because of the detailed nature of the research questions, particular care had to be used in the development of sample frames for the three groups: program participants or people who had received a rebate through the program; program non-participants or people who had purchased a new furnace outside the program during 2002 or 2003; and trade allies. The final sample consisted of 100 participants, 100 non-participants, and 40 trade allies.

As the evaluation design includes the use of billing analysis to determine the impact of the program, care was taken to screen potential respondents for acceptable billing histories prior to launching the telephone survey[2]. All participants were screened, and approximately 2,100 of the 2,915 were determined to have valid consumption history for the year prior to the program. In addition, a list of 35,000 potential candidates was developed for use in surveying a comparison group. This large list was required as the comparison group was defined as household that had purchased a furnace outside of the program and the incidence was estimated at 2.7% of the population. This list was also screened against the participants list to reduce the probability of surveying a person twice.

The telephone surveys were conducted between May 25 and June 6 of 2003 using a CATI system. Interviewers were fully briefed before the surveys were conducted to ensure that they understood the intent of the overall survey as well

[2] The methodology used for screening the billing history is included as Appendix A.

as each individual question. Up to five calls were made to each potential respondent to minimize response bias. Qualifying questions were asked to ensure that the appropriate individual completed the survey. As the responses were given, they were entered into an electronic database. Responses were then edited and cleaned.

Analysis of energy savings due to the program requires some care, because replacement of an existing, typically standard efficiency furnace with a new furnace (with minimum AFUE of 78% under the regulations of the Energy Efficiency Act) will substantially reduce natural gas consumption, whether or not a high efficiency furnace is installed. Energy savings due to the program will fall into two categories. First, for all customers, direct savings include the impact of moving from a mid efficiency furnace to a high efficiency furnace. Second, for some customers the program induced them to replace their furnace sooner than they otherwise would have. These spillover savings include the savings of moving from a standard efficiency furnace to a mid efficiency furnace for the early replacement period.

The billing analysis conducted for the 2002 Residential Heating System Upgrade Program[3] determined that the efficiency of the average furnace replaced during that year's program was 70.6%. This estimate is used for the 2003 evaluation rather than the 60% estimate used previously. This study also estimated the consumption of the average replaced furnace at 91.5 GJ.

Direct annual energy savings are based on Equation (1).

(1) Energy savings = 91.5 GJ * (0.706/0.78 – 0.706/0.920)*(1 - FR)*(Gross participants)

where 91.5 GJ is the estimated base space heating load for program participants, 0.706 is the assumed AFUE for the old furnace or boiler, 0.920 is the typical AFUE for high efficiency natural gas furnaces, 0.780 is the minimum AFUE under the regulations of the Energy Efficiency Act, (1 – FR) is one minus the free rider rate estimated from residential customer survey data, and gross participants is the number of furnaces receiving rebates from program data in 2003. These savings pertain to the expected life of the furnace.

In addition to the direct annual energy savings noted above, it was determined through the surveys that the program induced people to replace furnaces earlier than they otherwise would have. This is classed as spillover savings and the estimation is based on Equation (2).

(2) Energy savings = 91.5 GJ * (0.706/0.706 – 0.706/0.780)*(Gross early participants)* (Average years replaced early)

where 91.5 GJ is the estimated base space heating load for program participants,

[3] "Billing Analysis – 2002 Residential Heating System Upgrade Program Evaluation", Terasen Gas, July 28, 2004

0.706 is the assumed AFUE for the old furnace or boiler, 0.780 is the minimum AFUE under the regulations of the Energy Efficiency Act, gross early participants is the attribution rate (or the share of furnaces replaced prematurely due to the program from customer survey data) times the number of furnaces rebated from program data in 2002. These savings pertain to the number of years the furnace would have been used before replacement.

Peak savings are based on Equation (3).

(3) Peak savings = (January's monthly share of annual heating degree days)*(1/31 days)*Energy savings.

3. Program Description

3.1 Program Design and Implementation

The original purposes of the Heating System Upgrade Program was to encourage home owners to consider energy efficiency when they were making furnace replacement decisions and ultimately to reduce peak natural gas demand, delay the need for incremental system investments, and reduce greenhouse gas emissions due to the residential sector. During program design, research was undertaken to understand residential customer needs and the advantages and weaknesses of alternative program designs.

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This incentive was combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers. For the 2003 program, the furnace or boiler had to be purchased from September 1, 2003 to December 15, 2003. Participants had the choice of receiving a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada or interest free financing from Homeworks. In addition, participants who chose a furnace with a VSM could also receive a further $ 150 incentive from BC Hydro or Aquila towards the costs of the furnace. Details of the manufacturers' offers vary by manufacturer as shown below in Exhibit 3.1.

Exhibit 3.1. Manufacturers' Rebates

Manufacturer / Product	Terasen Gas and NRCan Rebate	Manufacturer Offer
American Standard – Furnace	$300	10-year parts and labour warranty total valued at $530.
Armstrong – Furnace	$300	Programmable thermostat plus electrostatic filter total valued at $200
Bryant - Furnace/Boiler	$300	10-year parts warrantee plus a programmable thermostat valued at $500
Carrier – Furnace	$300	10-year parts warrantee plus a programmable thermostat valued at $500
Frigidaire – Furnace	$300	Programmable thermostat and $100 discount off installation for a value of $ 200
IBC Technologies Inc. – Boiler	$300	Variable speed pump valued at $350.
Keeprite – Furnace	$300	$150 rebate
Kenmore – Furnace	$300	$150 rebate
Lennox – Furnace	$300	10-year parts and labour warranty valued at $600
Luxaire - Furnace	$300	$150 rebate
Super Hot – Boiler	$300	2-year parts and labour and 15-year heat exchanger warrantee valued at $200.
Tempstar – Furnace	$300	$150 rebate
Trane – Furnace	$300	10-year parts and labour extended warranty total valued at $350-$560
Weil-McLain – GV / Ultra Boiler	$300	$150 rebate (GV) or $ 150 plus 5-year parts and labour warrantee (Ultra) valued at $ 450
York – Furnace	$300	10-year parts and labour extended warranty plus programmable thermostat total valued at $600

3.2 Program Marketing

The Heating System Upgrade Program has used a variety of mechanisms to ensure that potential clients are aware of the program. These mechanisms have included:

- Bill inserts and messages.
- Advertising in Homewest magazines.
- Direct mail.
- Terasen Gas web site advertising.
- Promotion at retail outlets (POP).
- The manufacturers' dealer networks.
- Trades and contractors.
- Call center operators.

3.3 Delivery

In order to receive a rebate, the customer had a high efficiency furnace installed, completed a rebate coupon, attached a copy of the invoice, and forwarded the coupon and the invoice to Terasen Gas' billing area (managed by Accenture Business Services for Utilities (ABSU)). If the required criteria were met, the rebate was processed and the customer's information entered into the program data base. If the relevant criteria were not met, a letter was sent to the customer informing them that the rebate was refused and explaining the reason why. If critical information was missing, a letter was sent to the customer with information on what was missing.

The 2003 program had two significant changes from previous year's program. The first change was that a financing plan was offered, and the second change was that an additional incentive was provided if the furnace included a high efficiency variable speed fan motor (VSM).

The financing plan provided 0% financing over 24 months, on approved credit, for a personal loan between $ 2,000 and $ 4,000. The financing was in lieu of the $ 300 grant. The program was administered by Homeworks Financing, with funding from Citizens Bank of Canada. Administration of the financing program was handled by Homeworks. Some 211 participants took part in the financing program, of which 109 also received the incentive for the VSM.

The high efficiency variable speed motor incentive provided an additional $ 150 if the furnace included an approved variable speed furnace blower motor. This incentive was provided by BC Hydro, Aquila Networks Canada, and Natural Resources Canada. 1,612 participants, or just over 55%, took advantage of this offer.

3.4 Rationale

The rationale for the Heating System Upgrade Program is based on the premise that by providing customers with information on the advantages of high efficiency furnaces together with a financial incentive, customers will be encouraged to install high efficiency furnaces. This will result in significant energy conservation retrofits and measurable reductions in energy consumption and carbon dioxide emissions. Exhibit 3.1 outlines the rationale for the program and its activities. In summary, for each activity, the main linkages among inputs-outputs-outcomes and impacts are shown. There are strong and plausible linkages for each part of this chain confirming the logic of program design.

Exhibit 3.2. Program Logic Model

	Program design and implementation	Program marketing	Program delivery
Inputs	Assess customer needs and develop a program to meet these needs	Promotional activities including bill inserts, website, direct mail	Processing of applications and dispatch of letters to customers
Outputs	Program designed and implemented	Customer awareness of and interest in program increased	Provision of rebates to qualifying customers
Outcomes	Systems in place and operational	Increased customer intent to participate	Improved installation rate for high efficiency furnaces
Impacts	Reduced residential energy and peak consumption Reduced residential energy bills Reduced greenhouse gas emissions		

4. Customer Survey Results

4.1 Customer Awareness

Awareness of a program is the first step in the chain of actions that may eventually lead to program participation. Awareness of the Heating System Upgrade Program for non-participants is shown in Exhibit 4.1 as 31%. In 2002 the awareness level of the program by non-participants was 41% and awareness appears to have declined between 2002 and 2003.

Exhibit 4.1.1. Awareness of Heating System Upgrade Program

	Non-Participants 2003 (%)
Base	100
Yes	31%
No	67%
DK/NR	2

Understanding the importance of sources of program awareness is critical in evaluating the success of promotional strategies. The sources of overall awareness of the program, for those who indicated their awareness of the program in the previous question, are shown in Exhibit 4.1.2. For participants, the most important sources are: insert in Terasen Gas bill, the heating contractor, and word of mouth. For non-participants, the most important sources are the insert in Terasen Gas bill, and the heating contractor.

Exhibit 4.1.2. Source of Program Awareness

	Total (%)	Participants (%)	Non-participants (%)
Base	131	100	31
Insert in Terasen Gas bill	46	44	52
Heating contractor	15	16	10
Word of mouth	11	13	6
Newspaper or Magazine adv.	9	10	6
Direct mail	4	3	6
Terasen web site	4	4	3
Radio advertisement	2	1	6
Salesman / dealer	2	2	3
Home show	2	3	-
TV advertisement	2	2	-
NRCan web site	1	1	-
Other	2	2	-
DK/NR	4	3	6

4.2 Customer Satisfaction

Customers were asked what they liked and least liked about the promotion. Exhibit 4.2.1 shows the major responses. The response is quite favorable with saving money being the first attraction and energy efficiency as the second. Sixty-seven percent (67%) of the respondents had nothing about the program they least liked. Of the 31% of non-respondents who were aware of the program, energy efficiency and saving money were also the main attraction, but non-respondents did not like the restrictions on the types of furnaces. However 58% of the non-respondents had nothing they liked least about the program.

Exhibit 4.2.1. "What did you like about the program"

	Total (%)	Participants (%)	Non-participants (%)
Base	131	100	31
Saving money / got money back	46	55	16
Saved money / more efficient furnace / needed a new furnace	21	27	-
Energy efficiency / good for environment	13	11	19
Informative / easy to understand	6	6	6
Saved money on gas bill	5	5	3
Financing / ability to pay in installments	3	3	3
Warrantee	2	2	-
Other	5	6	1
Nothing in particular	17	7	48
DK/NR	2	1	6

Exhibit 4.2.2. "What did you least like about the program"

	Total (%)	Participants (%)	Non-participants (%)
Base	131	100	31
Rebates not available for all types of furnaces	6	1	23
Lack of information	5	7	-
Rebate was too low	5	6	3
Amount of paperwork / too complicated	3	3	3
Time limit for promotion	3	2	6
Time it took for money to appear	2	3	-
Rebate should apply to self install	2	-	6
Other	3	4	-
Nothing in particular	67	70	58
DK/NR	4	4	3

Customers were asked to indicate their level of satisfaction with the rebate program components on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 4.2.3 shows the reported levels of satisfaction with the standard errors shown in parentheses. Participants reported a satisfaction level of 4.2 on the application procedure, and just under 4.0 for information on the program, and information on efficient furnaces. The lowest satisfaction was reported for the time period and amount of the rebate. These are high and significant levels of satisfaction.

Exhibit 4.2.3. Customer Satisfaction with Program Components (mean on 5-point scale)

	Participants (%)
Base	100
Application procedures	4.2 (0.1)
Information on the rebate program	3.9 (0.1)
Information about efficient furnaces	3.9 (0.1)
Type of furnaces eligible for rebate	3.8 (0.1)
Time period for purchasing rebate eligible furnace	3.7 (0.1)
Amount of the rebate	3.7 (0.1)

Note: Standard error in parentheses.

Twenty-eight percent of program participants reported calling the customer call center with regards to the program. Exhibit 4.2.4 outlines the reasons for the calls, most of which focused on understanding the rebate and / or their eligibility for the rebate.

Exhibit 4.2.4. Purpose of this call

	Participants (%)
Base	28
To understand the rebate	39
To clarify eligibility for incentive	32
To understand finance plan	11
To determine if furnace was eligible	11
General information about program	11
How to apply	7
To determine when rebate would appear	4
DK/NR	14

Customers were asked to indicate their level of satisfaction with the various aspects of their furnace on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 4.2.5 shows the reported levels of satisfaction with the standard errors shown in parentheses. Participants reported satisfaction levels averaging 4.0 or more for reliability of the furnace, ease of installation of furnace, gas consumption, and after sales service. Non-participants reported satisfaction levels of 4.0 or more for all elements of the program except for the amount of their natural gas bill, which likely reflects the higher share of mid efficiency furnaces that they have purchased.

Exhibit 4.2.5. Customer Satisfaction with Their Furnace (mean on 5-point scale)

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Reliability of furnace	4.5 (0.1)	4.5 (0.1)	4.6 (0.1)
Ease of installation of furnace	4.4 (0.07)	4.3 (0.11)	4.4 (0.09)
Natural gas consumption	4.1 (0.1)	4.0 (0.1)	4.2 (0.1)
After sales service	4.1 (0.1`)	4.0 (0.1)	4.3 (0.1)
Price of furnace	3.8 (0.1)	3.6 (0.1)	4.1 (0.1)
Amount of natural gas bill	3.8 (0.1)	3.8 (0.1)	3.7 (0.1)

Note: Standard error in parentheses.

Respondents were asked if they had any problems with their new furnace. As Exhibit 4.2.6 shows, the share of respondents reporting problems was about 15%, 21% for participants and about 9% for non-participants. By furnace blower, 18% of those with VSMs had problems while 14% with standard furnace motors experienced difficulties. This difference is quite small, but may indicate that there are still some problems with this relatively new technology.

Exhibit 4.2.6. Had any Problems with Furnace

	Total (%)	Participants (%)	Non-participants (%)	PSC	VSM
Base	200	100	100	74	111
Yes	15	21	9	14	18
No	85	79	91	86	82
DK/NR	-	-	-		

Respondents were then asked about the types of problems experienced. Among those with problems with their furnace, the most common problems were: the furnace had required major repairs; the furnace was too noisy; and furnace had excessive vibration. Exhibit 4.2.7 summarizes the types of problems encountered. Excess noise was the most common complain. A detailed review of the responses indicated that this problem was reported almost three times as often by customers with VSMs. Similarly, excess vibration was also reported more often for furnaces with VSMs. (Note: This may result from a known problem when VSMs are installed in houses where the duct work is too small, which can result in both noise and vibration. If so, this may be addressed through contractor / sales staff training).

Exhibit 4.2.7. Have you experienced any of the following problems with your furnace?

	Total (%)	Partici-pants (%)	Non-partici-pants (%)	PSC (%)	VSM (%)
Base	30	21	9	10	20
Furnace too noisy	37	29	56	20	45
Furnace has required major repairs	13	10	22	10	15
Furnace cycles off and on too frequently	13	10	22	20	10
Furnace has excess vibration	10	10	11	-	15
Leaks / condensation problems	10	14	-	-	15
The fan needed to be replaced	7	10	-	10	15
Furnace produced an uncomfortable draft	7	5	11	20	-
Difficult to maintain the right temperature	3	5	-	-	10
Furnace size is too small	3	-	1	-	-
Other	27	38	-	30	25
DK/NR	7	5	11	10	5

*Note: Multiple Responses – columns will not sum to 100%.

4.3 House Comfort

Information was collected on a variety of issues related to home comfort and secondary heating to better understand why households choose different levels of efficiency, interest in VSM, and to help explain changes in the use of secondary heating following Participants reported a higher level of increased comfort than did non-participants. Similarly, households with VSMs reported a higher level of comfort than those with PSCs[4]. For participants with VSMs, the level of increased comfort was 78% compared with 58% overall for PSCs.

[4] Permanent Split Capacitor Motors (PSC) are the predominant technology used to power furnace blowers. Typically, they can be installed to operate at one of 3 or four predetermined speeds. A variable speed motor (VSM) can operate through a range of speeds depending on the needs of the heating system.

Exhibit 4.3.1. Has comfort in house increased, decreased or stayed the same.

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	200	100	100	74	111
Increased	67	76	57	58	77
Decreased	1	1	1	1	1
Remained the same	29	21	36	32	21
DK/NR	4	2	6	8	1

Respondents were then questioned to determine in what way comfort increased or decreased. The major factors are: more even temperature; house warmer; quieter; and house more comfortable. Surprisingly, stated differences were small between PSC and VSM motors with the exception of more even temperature and lower noise, both selling points for VSM motors. Two respondents reported decreased comfort due to cool drafts and long cycle times for the furnace.

Exhibit 4.3.2 In what way has comfort increased?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	133	76	57	43	85
More even temperature	59	68	47	49	68
House warmer	26	28	25	35	22
Quiet fan / less noise	15	18	11	9	18
House more comfortable	14	14	14	19	11
Previously cold rooms warmer now	8	7	11	9	6
House heats faster	8	5	11	9	7
Temperature more constant	8	12	2	12	6
Indoor air quality has improved	7	5	9	5	8
Thermostat more effective / easier to use	4	5	2	2	5
Furnace runs for shorter periods	2	1	4	2	2
Drafts have been reduced	2	1	2	0	2
Other	6	4	9	5	7
DK/NR	2	1	4	2	1

Exhibit 4.3.3 In what way has comfort decreased?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	2	1	1	2	0
Cool drafts	50	-	100	-	100
Longer cycle time	50	100	-	100	-

4.4 Supplementary Heating

To help understanding changes in energy consumption associated with the installation of a new furnace, information was collected on the prevalence of supplementary heating, and how the use of supplementary heating changed when the new furnace was installed.

There are two cases to consider. First, if the use of supplementary heating is reduced after the furnace is installed, and if the alternate fuel is not natural gas, then the expected reduction in natural gas consumption may not take place as the heating load on the furnace has increased. Second, if the alternate fuel is natural gas, then the effect on natural gas consumption will depend on the relative efficiency of the secondary heating equipment relative to the high efficiency furnace, but may further increase the savings expected upon the installation of the high efficiency furnace as the heat is now provided by a more efficient appliance.

Exhibit 4.4.1 shows that about 64% of the participants have secondary heating, while Exhibit 4.4.2 shows that natural gas is the predominant fuel. Exhibit 4.4.3 shows the cross tabulation of the heating technologies used to provide secondary heat, and show that fireplaces are the predominant technology for natural gas.

The data in this section is also shown by furnace motor type, but no significant differences were observed.

Exhibit 4.4.1 Does your house have supplementary heating?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	200	100	100	74	111
Yes	64	64	63	61	64
No	37	36	37	39	36

Exhibit 4.4.2. What heating fuel is used for supplementary heating?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	127	64	63	45	71
Natural Gas	57	52	62	49	59
Electricity	29	31	27	29	31
Wood	28	28	29	44	20
Oil	2	2	2	2	1

Exhibit 4.4.3 For supplementary heating, what method is used?

	Total (%)	Participants (%)	Non-participants (%)
Base	51	30	21
Electricity	**24**	**30**	**14**
- Elec. baseboard	14	20	5
- Portable elec.	8	7	10
- Oil heat	2	3	-
- Fireplace	10	13	5
Natural Gas	**63**	**57**	**71**
- Fireplace	55	50	62
- Radiant elec.	2	3	-
- NG. wall heater	4	7	-
- NG stove	4	-	10
- Wood stove	2	3	-
- Elec baseboard	4	7	-
Wood	**24**	**20**	**29**
- Fireplace	12	7	19
- Wood Stove	12	13	10

Note: columns do not sum due to multiple responses

Exhibit 4.4.4 shows the change in use of secondary heating after the installation of the new furnace, and it shows that about 5% of participants increased their use of secondary heating while 47% reduced it. Assuming approximately the same amount of secondary heating usage, this indicates a net reduction of about 42% of secondary heating after the new furnace is installed.

Exhibit 4.4.4 Has your use of supplementary heating changed?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	127	64	63	45	71
Increased	5	5	5	2	4
Decreased	40	47	33	40	41
Remained the same	50	44	57	56	49
DK/NR	5	5	5	2	6

Respondents were also asked to estimate the amount of the reduction in secondary heating after the installation of the new furnace. Exhibit 4.4.5 shows a reduction of 52% overall, and 50% among program participants.

Exhibit 4.4.5. By how much has your use of supplementary heating decreased

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	51	30	21	18	29
Mean	52	50	55	63	43
0 – 24%	20	23	14	11	28
25 – 49%	20	17	24	22	17
50 – 74%	20	20	19	17	24
75 – 100%	35	33	38	50	21
DN/NR	6	7	5	-	10

4.5 Customer Characteristics

Information was collected on a variety of respondent characteristics. Exhibit 4.5.1 shows the age distribution of respondents. For participants, the largest group was in the age range 46-54 years and the second largest group was in the age range 55-64 years. For non-participants the largest group was in the age range of 65 years and over while the second largest group was in the 55 - 64 years age range. This could indicate that Terasen program promotion is not reaching the older age groups as effectively as it is the "middle aged".

Exhibit 4.5.1. Age of Respondents

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
25-34 years	6	9	2
35-44 years	15	17	12
45-54 years	23	28	17
55-64 years	27	23	30
65 years +	30	22	38
DK/NR	1	1	1

Marital status of respondents is shown in Exhibit 4.5.2. The participant sample has 3% singles, 90% married or common law; 2% divorced or separated; and 3% widowed. The non-participant sample also has 3% single but 75% married or common law; 5% divorced or separated; and 11% widowed.

Exhibit 4.5.2. Marital Status

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Singles	3	3	3
Married/common law	84	90	77
Divorced/separated	4	2	5
Widowed	7	3	11
DK/NR	3	2	4

Highest level of education attained by respondents is shown in Exhibit 4.5.3. The participant sample has larger share of respondents who have post high school education than the non-participant sample.

Exhibit 4.5.3. Highest Level of Education Attained

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Some high school	8	6	9
Completed high school	16	12	19
Some university/college	12	12	11
Completed university/college	30	30	30
Some trade/technical school	4	3	4
Completed trade/technical school	16	20	12
Post graduate	10	11	8
DK/NR	7	6	7

The number of people in the house is shown in Exhibit 4.5.4 with standard errors in parentheses. The total sample has an average of 2.6 people per house, the participant sample an average of 3.1 people per house and the non-participant sample an average of 2.6 people per house. This may reflect the older age group and higher level of widowed people in the non-participant group. To the extent that natural gas usage varies with household size, this indicates that the program is successfully targeting higher natural gas users. This consideration is also reflected in the discrete choice analysis which found that higher natural gas usage was a determinant of program participation.

Exhibit 4.5.4. Number of People in House

	Total	Participants	Non-participants
Base	200	100	100
Average	2.8 (0.1)	3.1 (0.1)	2.6 (0.1)

Note: Standard error in parentheses.

Exhibit 4.5.5 Number of People in House by Age

	Total	Participants	Non-participants
Base	200	100	100
0 – 18	0.6 (0.1)	0.7 (0.1)	0.5 (0.1)
19 – 24	0.2 (0.0)	0.3 (0.1)	0.1 (0.0)
25 – 34	0.2 (0.0)	0.3 (0.1)	0.1 (0.0)
35 – 44	0.3 (0.0)	0.4 (0.1)	0.3 (0.1)
45 – 54	0.5 (0.1)	0.6 (0.1)	0.4 (0.1)
55 – 64	0.5 (0.1)	0.5 (0.1)	0.5 (0.1)
65 and older	0.6 (0.1)	0.4 (0.1)	0.7 (0.1)
DK/NR	5%	8%	1%

4.6 Furnace Characteristics

Respondents were asked a range of questions about the replaced furnaces. The average age of furnaces at time of replacement was about 24.9 years overall, about 24.2 years for participants and about 25.5 years for non-participants. This tends to support that the program encourages people to replace their furnaces earlier than they otherwise would. The share of furnaces working at time of replacement was about 93% overall, with no difference between participants and non-participants.

Exhibit 4.6.1. Characteristics of the Replaced Furnace

	Total	Participants	Non-participants
Base	200	100	100
Age of the furnace at time of replacement (years)	24.9 (0.6)	24.2 (0.9)	25.5 (0.9)
Was furnace working at time of replacement (respondent share stating furnace was working)	93%	93%	93%

Note: Standard error in parentheses.

The efficiency level of the new furnace is shown in Exhibit 4.6.2. All furnaces purchased by participants were of course high efficiency, but the reporting of 7% of these high efficiency furnaces as mid efficiency highlights the difficulty consumers have with understanding the actual efficiency level of their furnace. Sixty percent (60%) of furnaces purchased by non-participants were noted as high efficiency. However, there is some uncertainty as to the accuracy of the reported incidence of high efficiency furnaces by non-participants due to their limited understanding the actual efficiency of the installed furnace.

Exhibit 4.6.2. Efficiency Level of New Furnace

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Mid efficiency	34	7	60
High efficiency	66	92	39
DK/NR	1	1	1

The efficiency level of the previous furnace is shown in Exhibit 4.6.3. About 93% of total respondents had a standard efficiency furnace while 97% of participants and 89% of non-participants had a standard efficiency furnace.

Exhibit 4.6.3. Efficiency Level of Previous Furnace

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Standard efficiency	93	97	89
High efficiency	5	2	7
DK/NR	3	1	4

The capacity of the new furnace is shown in Btus per hour in Exhibit 4.6.4. The average furnace heating capacity for the whole sample is about 80,000 Btuh, for participants is about 78,000 Btuh and for non-participants is about 82,000 Btuh. However the high DK/NR level indicates these numbers are based on a relatively small sub-sample, which raises concerns about the representativeness of the data.

Exhibit 4.6.4. Capacity of New Furnace (Btu per hour)

	Total (BTU)	Participants (BTU)	Non-participants (BTU)
Base	200	100	100
Average	79,966 (2,734)	77,906 (3,677)	82,407 (4,112)
DK/NR	71%	68%	73%

Note: Standard error in parentheses.

Respondents were asked about the behavior of their previous furnace fan as indicated in Exhibit 4.6.5. Before the furnace change, about 9% of all fans ran continuously with this share at 14% for participants and 4% for non-participants. The last two columns show the type of fan motor chosen in the new furnace.

Exhibit 4.6.5. Furnace Fan Behavior Before Furnace Change

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	200	100	100	74	111
Intermittently when providing heat	52	53	51	51	57
Continuously during heating season	8	6	10	9	6
Intermittently when providing heat / AC	12	13	11	11	13
Continuously during heating / AC season	4	1	7	5	4
Intermittently to also provide ventilation	5	5	4	1	7
Continuously	9	14	4	7	12
No furnace fan (boiler)	5	4	5	4	5
DK/NR	6	4	8	11	3

For people who indicated that they also used their fan intermittently to provide ventilation, Exhibit 4.6.6 shows the number of months per year than the furnace is used in this mode.

Exhibit 4.6.6 Months of use to "also provide ventilation"

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	9	5	4	1	8
Intermittently when providing heat	6.5 (1.6)	8.3 (2,6)	4.8 (1.9)	12.0	5.0

Exhibit 4.6.7 shows the furnace fan usage after the furnace is replaced. Of particular note is the reduction in intermittent use when providing heat only and the increase in intermittent use when providing heating and air conditioning. This may be indicative of the installation of central air conditioning at the time the furnace is being replaced. Also the continuous use of ventilation appears to increase for program participants.

Exhibit 4.6.7. Furnace Fan Behavior After Furnace Change

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	200	100	100	74	111
Intermittently when providing heat	39	37	41	43	35
Continuously during heating season	5	5	5	4	6
Intermittently when providing heat / AC	22	18	25	24	18
Continuously during heating / AC season	10	7	12	8	11
Intermittently to also provide ventilation	7	8	5	3	9
Continuously	13	19	6	8	17
No furnace fan (boiler)	2	-	3	4	-
DK/NR	5	6	3	5	4

Exhibit 4.6.8 Months of use to "also provide ventilation"

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	13	8	5	2	10
Intermittently when providing heat	6.0 (1.2)	6.3 (1.2)	5.3 (3.4)	5.0	6.1

4.7 Variable Speed Blower Component

A series of questions were asked to better understand VSMs. The primary reasons for selecting VSMs are because of the energy efficiency and because the contractor recommended it. However, there is some reason to think that the non-participant VSM share is overstated as respondents have difficulty differentiating between VSMs and the multiple speed capability of PSC motors. Hence the data should be used with caution. It should also be noted that 10% of the participants with VSMs stated that they wanted continuous ventilation. The data also supports the idea that VSM sales are strongly influenced by the contractor as part of the sales process.

Exhibit 4.7.1 Why did you select a model with a VSM

	Total (%)	Participants (%)	Non-participants (%)
Base	115	69	46
It is more energy efficient	43	49	33
The contractor recommended it	23	19	30
It is quieter	8	10	4
Wanted continuous ventilation	6	10	-
Provides more comfortable ventilation	6	6	7
Keeps my house warmer	4	4	4
Operates through a range of speeds	4	7	-
Wanted better indoor air quality	4	7	-
Was motivated by the $ 150 rebate	4	7	-
Part of the better furnace I wanted	3	1	4
It provides even heat	3	4	-
The price was attractive	3	-	7
Salesman / dealer recommended it	2	1	2
It does not run continuously	1	-	2
Other	9	7	11
No reason in particular	2	1	2
DK/NR	10	10	11

Exhibit 4.7.2 further supports the idea that VSM sales largely develop during the sales process, as only 23% of purchasers were aware of the product prior to installing the new furnace, and only 18% had considered purchase. However participants were more knowledgeable than the non-participants.

Exhibit 4.7.2. Prior to installing this furnace, were you aware of, or considering the purchase of a VSM?

	Total (%)	Participants (%)	Non-participants (%)
Base	115	70	85
Aware of	23	34	14
Considering purchase	18	24	13
No	58	41	72
DK/NR	1	-	1

Exhibit 4.7.3 shows the sources of awareness, and again indicates that the contractors are the single largest source of awareness, and when combined with the sales / dealer component account for 32% of the awareness.

Exhibit 4.7.3. Sources of awareness

	Total (%)	Participants (%)	Non-participants (%)
Base	64	41	23
Contractor	19	17	22
Word of mouth	13	15	9
Salesmen / dealers	13	15	9
Terasen Gas	11	10	13
Internet (general)	9	12	4
Manufacturer's website	8	5	13
My work	6	2	13
Homeshow	5	7	-
Federal government	5	7	-
Newspaper	2	2	-
Other	13	12	13
DK/NR	14	15	13

People who purchased a furnace without a VSM were asked why they had done so. For the total sample, the largest reason is cost at 28% (sum of 'furnace too expensive' plus "too expensive') followed by lack of awareness at 23%.

Exhibit 4.7.4. Reasons for not purchasing a furnace with a VSM

	Total (%)	Participants (%)	Non-participants (%)
Base	40	31	9
Unaware of VSM	23	29	-
Furnace with VSM was too expensive	15	13	22
Contractor did not recommend it	15	13	22
Too expensive	13	10	22
Participant w/ PSC who insisted it was VSM	8	10	-
VSM not available on furnace I choose	5	-	22
Other	5	6	-
Did not need a VSM	5	-	22
DK/NR	18	22	-

4.8 Housing Characteristics

Dwelling type for respondents is shown in Exhibit 4.8.1. Single detached homes dominated the sample, with the share of single detached dwellings at 96% for the whole sample, with no significant difference between participants and non-participants.

Exhibit 4.8.1. Dwelling Type

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Single detached	96	96	95
Semi detached (duplex)	1	2	2
Row/townhouse	2	2	2
Mobile/other	2	2	2

The average age of the house is shown in Exhibit 4.8.2. The average age of dwelling was 29 years overall, 28 years for participants, and 31 years for non-participants, again perhaps reflecting the older age group in the non-participants.

Exhibit 4.8.2. Age of Home

	Total	Participants	Non-participants
Base	200	100	100
Years	29.3 (0.8)	28.0 (1.0)	30.5 (1.1)

Note: Standard error in parentheses.

Exhibit 4.8.3 shows the heated area of the home. The difference in size between participants and non-participants is not statistically significant.

Exhibit 4.8.3. Heated Area of Home

	Total	Participants	Non-participants
Base	200	100	100
Square Feet	2018 (72.7)	2059 (65.0)	1975 (132.6)

Note: Standard error in parentheses.

Natural gas uses in the dwelling are shown in Exhibit 4.20. Main uses are water heating, space heating, fireplaces, secondary space heating, cooking and barbequing. Less important uses are clothes drying, hot tubs, pool heating and patio heaters.

Exhibit 4.8.4. Natural Gas Uses in the Home

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Water heating	86	93	79
Main Space heating	80	76	83
Fireplace insert	50	50	49
Secondary Space heating	45	34	55
Cooking	20	21	18
Barbeque	16	18	14
Clothes drying	7	8	6
Hot tub	2	2	2
Outdoor pool heating	3	4	1
Patio Heater	1	1	-
NR	4	2	6

4.9 Program Design

A number of issues were explored to help with the design of a possible future program, including influencers of heating system choice and importance of the various incentives.

Exhibit 4.9.1 reflects the major influencers on customers' choice of heating system. For the total sample, energy efficiency was the strongest influencer, closely followed by comfort in the home. It is interesting to note that operating cost of the heating system was consistently ranked as more important than the initial cost. Indoor air quality also receives a significant ranking.

Exhibit 4.9.1 Influencers on choice of home heating system

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Energy Efficiency	4.5 (0.1)	4.6 (0.1)	4.4 (0.1)
Comfort in your home	4.4 (0.1)	4.3 (0.1)	4.6 (0.1)
Operating cost of the system	4.3 (0.1)	4.4 (0.1)	4.3 (0.1)
Indoor air quality	4.2 (0.1)	4.2 (0.1)	4.2 (0.1)
Both initial and operating costs	4.1 (0.1)	4.1 (0.1)	4.2 (0.1)
Initial cost of the system	3.9 (0.07)	3.8 (0.11)	4.0 (0.09)

Note: Standard error in parentheses.

A series of questions was asked to determine the relative merits of the $ 300 incentive and the financing plan. Exhibit 4.9.2 shows the shares for the choice of grant vs. the financing program.

Exhibit 4.9.2. Incentive Choice

	Participants (%)
Base	100
$ 300 Rebate	89
Financing	7
DK/NR	4

Exhibit 4.9.3 shows that the primary reason for choosing the grant was that the participants had sufficient funds to pay for the upgrade, or did not want to borrow money.

Exhibit 4.9.3. Reason for choosing $ 300 grant

	Participants (%)
Base	89
Had money to pay for furnace	66
Rebate was of more value to me	15
Do not like finance / get into debt	11
Alternative financing / Sears 0%	3
Too much paperwork	2
Not aware of financing option	2
Other	6
No reason in particular	2
DK/NR	3

Conversely, the people who chose financing were predominantly those who did not have sufficient funds to pay for the upgrade.

Exhibit 4.9.4. Reason for choosing Financing

	Participants (%)
Base	7
Financing was of more value to me	43
Did not have money to pay for furnace	43
Interest rate was more attractive than loan	29
Other	14
DK/NR	14

Exhibit 4.9.5 shows that 57% of the people who chose financing would not have purchased a furnace at this time without the financing plan. This represents an additional 120 furnaces. As furnace sales only increased by 130 units between 2002 and 2003, it can be argued that the finance program was largely responsible for this increase in participation.

Exhibit 4.9.5. Would you have purchased furnace at this time if no finance plan?

	Participants (%)
Base	7
Yes	43
No	57

The 2003 program represented the first time that Homeworks was involved in the program (to provide the financing) and they appear to have done a satisfactory job of meeting participants' expectations.

Exhibit 4.9.6. How satisfied were you with the service provided by Homeworks?

	Participants (%)
Base	7
Extremely satisfied	14
Very satisfied	57
Somewhat satisfied	29

Respondents were asked if they were familiar with the Energy Star label for furnaces. About 51% of the overall sample, 67% of participants and 35% of non-participants were aware of the Energy Star label. This compares with about 43% of the overall sample, 47% of participants and 38% of non-participants from the 2002 survey, and indicates that awareness of the Energy Star label is still increasing.

Exhibit 4.9.7. Familiar with the Energy Star Label for Furnaces

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Yes	51	67	35
No	46	29	63
DK/NR	3	4	2

Respondents were asked if they found an Energy Star label on the furnace they bought. About 75% of the overall sample, 88% of participants and 51% of non-participants found the Energy Star label. This compares with about 65% of the overall sample, 70% of participants and 59% of non-participants in the 2002 survey and again supports an increasing awareness of the Energy Star label.

Exhibit 4.9.8. Found an Energy Star Label for Furnace that was Purchased

	Total (%)	Participants (%)	Non-participants (%)
Base	102	67	35
Yes	75	88	51
No	10	1	26
DK/NR	15	10	23

Exhibit 4.9.9 shows that participants strongly support the inclusion of Energy Star products in the program.

Exhibit 4.9.9 Importance of including Energy Star products

	Participants
Base	67
Yes	4.6 (0.1)
DK/NR	1%

4.10 Furnace Prices

Respondents were asked the installed price of their new furnace, including any applicable taxes. Exhibit 4.10.1 shows the mean price paid for participants, non-participants who purchased standard efficiency furnaces and non-participants who purchased high efficiency furnaces. The average prices paid were $3176 overall, and $3727 for participants. However the $2528 for non-participants buying standard efficiency furnaces and $2577 for non-participants buying high efficiency furnaces does not appear reasonable when compared with available information on furnace prices. It should be noted that the price difference stated for PSC and VSM equipped furnaces is influenced by the fact that VSMs are almost exclusively found in 2-stage furnaces, while single stage furnaces still predominates the PSC market. Further detail on the distribution of furnaces by price is given in Exhibit 4.10.2.

Exhibit 4.10.1. Furnace Prices (dollars)

	Total (all)	Participants (high efficiency)	Non-participants (mid efficiency)	Non-participants (high efficiency)	Part. PSC	Part. VSM
Base	200	100	60	39	35	65
Mean	3,176	3,727	2,528	2577	2999	4110
Std. error	98.4	124.9	169.0	168.5	157.9	148
DK/NR	21%	16%	30%	21%	17%	15%

Exhibit 4.10.2. Distribution of Furnaces by Price (percentage)

	Total (all)	Participants (high efficiency)	Non-participants (standard efficiency)	Non-participants (high efficiency)
$999 or less	1.0	-	2	3
$1000-$1999	8	3	17	8
$2000-$2999	27	15	33	44
$3000-$3999	17	22	8	18
$4000-$4999	18	31	3	5
$5000-$5999	6	8	3	3
$6000-$6999	3	4	2	-
Over $7000	2	1	-	-
DK/NR	21	16	30	21

4.11 Free Rider and Spill Over Analysis

Program participants were asked how important the Heating System Upgrade Program was in their decision to install a high efficiency furnace, where one was not at all important and five was very important as shown in Exhibit 4.11.1. To summarize the impact of the program, a weighted average of the importance scores was calculated, where the weights were as follows: score of five has weight of 1.00, score of four has weight of 0.75, score of three has weight of 0.50, score of two has weight of 0.25 and score of one has weight of 0.00. The weighted average of the importance scores is one minus the free rider rate, and indicates a free rider rate of about 43%.

Exhibit 4.11.1. Free Rider Analysis – Furnace program

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.20	0.28	0.25	0.12	0.11	
Product	0.20	0.21	0.13	0.03	0.000	0.57

Program participants were asked if they replaced the furnace early because of the availability of the rebate. As Exhibit 4.11.2 indicates 43% of participants indicated that they had replaced the furnaces early by an average of 2.5 years because of the availability of the rebate. Weighted across all respondents, furnaces were replaced an average of 1.08 years early because of the availability of the rebate.

Exhibit 4.11.2. Spill Over Analysis

	Replaced early (%)	Years replaced early	Weighted average years replaced early
Base	100	43	
Yes	43	2.5	1.08
No	53	0.00	0.000
DK/NR	4	-	-
Total participants	-	-	1.08

Those program participants who had chosen the VSM component of the program were asked how important the $ 150 incentive was in their choice of furnace. Using the same methodology as above, the weighted average of the importance scores is one minus the free rider rate, and indicates a free rider rate of 39%.

Exhibit 4.11.3. Free Rider Analysis – VSM component

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.20	0.34	0.26	0.08	0.12	
Product	0.20	0.26	0.13	0.02	0.000	0.61

5. Trade Ally Survey Results

Trade ally support of the program is critical to the transformation of the natural gas furnace market. Terasen's records show that 443 registered contractors provided updates to participate in the program. This represents about 23% of the registered contractors in BC, but a much larger percentage of the furnaces sold. For the 2003 evaluation, the number of Trade Allies surveyed was increased from 20 to 40, and based on the average number of employees this had the effect of including more of the smaller contractors.

5.1 Trade Ally Satisfaction

Trade allies were asked to indicate their level of satisfaction with program components on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 5.1.1 shows the reported levels of satisfaction with the standard errors shown in parentheses. Trade allies reported satisfaction levels averaging 4.0 or more for the amount of the rebate and the types of furnaces eligible. They expressed the lowest level of satisfaction with the time period for purchasing an eligible furnace.

Exhibit 5.1.1. Trade Ally Satisfaction with Program (mean on 5-point scale)

	Component 2003
Base	40
Amount of the rebate	4.1 (0.1)
Types of furnaces eligible for a rebate	4.1 (0.2)
Information on the rebate	3.8 (0.2)
Application procedures to obtain the rebate	3.8 (0.2)
Amount of the financing	3.5 (0.3)
Duration of the financing (24 months)	3.5 (0.3)
Information on the financing option	3.4 (0.3)
Time period for purchasing an eligible furnace	2.9 (0.2)

Note: Standard error in parentheses.

5.2 Trade Ally Characteristics

The average number of employees in reporting firms was 5.5 with a standard error of 0.7. This is a decrease from the 2002 survey, where the average number of employees was 8.1.

Exhibit 5.2.1. Number of Employees

	Share 2003 (%)	Share 2002 (%)
Base	40	20
Mean	5.5 (0.7)	8.10 (1.56)
Up to 2	35.0	20.0
3 to 5	24.0	30.0
6 to 11	28.0	20.0
Over 12	13.0	30.0

Note: Standard error in parentheses.

The main type of business is shown in Exhibit 5.2.2. The primary types of businesses were heating contractors, both independent and dealers, followed by plumbing and heating contractors.

Exhibit 5.2.2. Primary Business

	Share (%)
Base	40
Independent heating contractor	38
Furnace dealer & heating contractor	28
Plumbing and heating	15
Gas fitter	8
Mechanical contractor	8
Other	5

5.3 Furnace Characteristics

Trade allies were asked a number of questions about the replaced furnaces. Trade allies indicated that share of operating furnaces increased from 79% in the pre-program period to 84% during the program period as shown in Exhibit 5.3.1. This supports the idea that the program does influence customers to replace furnaces earlier than they might otherwise do.

Exhibit 5.3.1. Share of Furnaces Operational at Time of Replacement

	Share 2003 (Jan-Aug) (%)	Share Pgm (Sep-Dec) (%)
Mean	78.6 (4.6)	83.5 (3.3)
Up to 80%	42	39
81% to 90%	23	18
90% to 100%	33	18
DK/NR	5	45

Note: Standard error in parentheses.

Trade allies were asked to estimate the remaining life of furnaces at the time of replacement. The average remaining furnace life at replacement was estimated at about 5.3 years, slightly higher than the 4.5 years estimated in 2002.

Exhibit 5.3.2. Average Remaining Furnace Life at Replacement

	Share 2003 (Jan-Aug) (%)	Share Pgm (Sep-Dec) (%)
Base	40	40
Mean (years)	5.3 (0.5)	5.4 (0.5)
1 year or less	10	10
1 to 5 years	49	51
6 to 10 years	31	30
Over 10 years	0	0
DK/NR	13	10

Trade allies were asked if they routinely do a heat calculation as part of the pre-installation work. As Exhibit 5.3.3 indicates, about 48% of trade allies routinely do a heat calculation while about 53% of trade allies do not routinely do a heat loss calculation. This is a decrease from the 65% in 2002 who reported that they routinely did heat loss calculations, but may be more reflective of the practices of smaller firms in the 2003 sample than a change in the market practice.

Exhibit 5.3.3. Routinely do Heat Loss Calculation

	Share 2003 (%)
Base	40
Yes	48
No	53

Those trade allies who routinely do a heat loss calculation were asked what share of the time the heat loss calculation leads to a smaller capacity furnace. About 65% of the time, heat calculations leads to installation of a smaller capacity furnace.

Exhibit 5.3.4. Share of Time Heat Loss Calculation Leads to Smaller Capacity Furnace

	Share 2003 (%)
Base	19
Mean	64.6 (10.3)
0%	11
1% to 10%	16
11% to 50%	5
51% to 80%	10
81% to 100%	48
DK/NR	11

Note: Standard error in parentheses.

Respondents were asked to indicate the importance of the three incentives in affecting their customers' choice of furnace, where one is not at all important and five is very important, with standard errors in parentheses. This result shows that the $ 300 grant is considered to have a strong influence, while the financing program has a much lower impact. This is also reflected in the lower uptake on the finance program, which only accounted for about 7% of participation. The VSM incentive was assigned a low importance.

Exhibit 5.3.5. Trade Ally Views of Importance of Factors Affecting Choice of Furnace

	Share 2002 (%)
Base	40
Availability of rebate	4.0 (0.2)
Financing program	2.2 (0.2)
VSM incentive	2.9 (0.2)

Note: Standard error in parentheses.

A number of questions were asked to determine factors affecting trade ally recommendations to customers on choice of furnace. Exhibit 5.3.6 shows that about 17% of the locations are viewed as unsuitable for high efficiency replacement furnaces. This is a decrease from 25% in 2002.

Exhibit 5.3.6. Share of Customers for Which High Efficiency Furnace Not Economic due to Furnace Location

	Share 2003 (%)
Base	40
Mean	17.2 (3.2)
Up to 10%	55
11% to 40%	28
Over 40%	11
DK/NR	8

Note: Standard error in parentheses.

About 68% of trade allies believe that high efficiency furnaces are the best choice for their customers while another 23% believe that high efficiency furnaces are sometimes the best choice for their customers.

Exhibit 5.3.7. Believe that High Efficiency Furnaces Best Choice for Customers

	Share 2003 (%)
Base	40
Yes	68
No	10
Sometimes/depends on customer	23

A further question was asked to determine why contractors expressed these opinions. On the positive side, the main reasons centered on money or gas savings, reliable products and quietness. On the negative side, the primary reason was due to higher cost / longer payback period.

Exhibit 5.3.8. Why do you say this?

	Share (%)
Base	40
They will save money on gas	60
Too expensive / too long to recoup cost	18
They are reliable	13
They are quieter	10
They are easy to set up / install	8
Other furnaces are more reliable / last longer	8
They are better for the environment	5
Depends on the application / house factors	5
Other	15

Sometimes a two-stage furnace mid efficiency furnace is recommended as the preferred option as shown in the next Exhibit 5.3.9.

Exhibit 5.3.9. Recommend Two-stage Mid efficiency Furnaces as Preferred Option

	Share (%)
Yes	45
No	43
Sometimes/depends on customer	13

A further question was asked to determine why contractors expressed these opinions. The two main drivers for two-stage mid efficiency furnaces are: lower cost and "almost as efficient as HE furnace". This latter point is a misconception and perhaps should be addressed by Terasen in contractor communications.

Exhibit 5.3.10. Why do you say this?

	Share (%)
Base	40
They are less expensive	20
They are almost as efficient as HE furnaces	10
High efficiency furnaces are most cost effective	10
They are expensive	8
Quieter than single stage furnace	8
Provides more comfortable ventilation	5
Recommend them with a heat pump	5
Depends on the application / factors in house	5
Our suppliers do not carry them	5
They work better than single stage	5
Work well in this climate	5
We let our customers make the decision	3
Other	10
No particular reason	10

Contractors were asked for the shares of the various types of fan motor technologies sold throughout the year, and also the share of VSM motors sold during the program period. Exhibit 5.3.11 shows that the share of VSM motors increased from about 28% of sales to about 38%, or by about 36%.

Exhibit 5.3.11. Furnace Blower Motors Shares

	During all of 2003			Sep - Dec
	Single Speed PSC (%)	Multi Speed PSC (%)	VSM (%)	VSM (%)
Base	40	40	40	40
Mean*	16.6 (5.3)	55.1 (5.9)	28.2 (4.7)	38.3 (5.8)
0%	73	18	25	23
1% to 20%	8	8	23	13
21% to 50%	6	23	36	36
51% to 80%	5	24	11	8
81% to 100%	10	31	8	18
DK/NR	-	-	-	5

The main features of interest for VSM's are that they use less electricity, they are quieter and they provide more comfortable ventilation. The incentive ranked fourth. However, 10% of the respondents believe that the VSM results in reduced natural gas usage, when in reality it increases the natural gas usage. Again this is something that Terasen may wish to address with contractors.

Exhibit 5.3.13 shows the results of further probing for customer motivations.

Exhibit 5.3.12. VSM Features of interest to customers

	Share (%)
Base	40
Uses less electricity	48
Quieter	33
Provides more comfortable ventilation	15
$ 150 rebate	13
Operates through a range of speeds	10
Uses less gas	10
Other	10
DK/NR	18

Exhibit 5.3.13. Customer motivations to purchase a VSM equipped furnace

	Share (%)
Base	40
Customer wanted continuous ventilation	8
It uses less electricity	8
It uses less natural gas	8
Incentive program / rebate	5
Provides more comfortable ventilation	5
Customer wanted the “best” furnace	3
Contractor / sales person “sold” the feature	3
Other	8
Nothing else	30
DK/NR	28

The next two tables probe Contractors attitudes towards VSMs. Exhibit 5.3.14 shows that 58% of the contractors recommend VSMs while Exhibit 5.3.15 identifies the primary reasons as: uses less electricity, provides more comfort and is quieter. The main reason not to recommend them relates to the higher costs.

Exhibit 5.3.14. Recommend VSMs to Customers

	Share (%)
Base	40
Yes	58
No	18
Sometimes/depends on customer	23
DK/NR	3

Exhibit 5.3.15 Why do you say this?

	Share (%)
Base	40
It uses less electricity	38
It provides more comfortable ventilation	33
Too expensive / takes time to recoup the money	23
Quieter	21
More reliable	8
Depends on the application	5
We let our customers make the decision	5
Our suppliers do not carry them	5
Other	5
No reason in particular	3

5.4 Furnace Fan Usage

A series of questions was asked to determine how customers used their furnace fans prior to replacement, and how the fans were set up to operate in the new furnace. Based on Contractor reporting, the major difference in fan usage occurs in furnaces with VSMs, where the contractors report that there is a 33 percentage point increase in the use of continuous ventilation. This is higher than reported by customers and is further discussed in Section 6.

Exhibit 5.4.1. Furnace Fan Behavior for Existing Installations

	Total (%)
Base	40
Intermittently when providing heat	40.5
Continuously during heating season	7.4
Intermittently when providing heat / AC	9.3
Continuously during heating / AC season	6.9
Intermittently to also provide ventilation	13.8
Continuously	22.0
DK/NR	23.0

Exhibit 5.4.2. Furnace Fan Behavior after Installation of New Furnace

	High Furnace (%)	Mid Furnace (%)	VSM Furnace (%)
Base	40	40	40
Intermittently when providing heat	39.9	45.5	14.4
Continuously during heating season	3.6	7.7	4.0
Intermittently when providing heat / AC	12.3	7.8	10.7
Continuously during heating / AC season	8.7	6.6	14.2
Intermittently to also provide ventilation	9.3	10.2	1.8
Continuously	26.4	22.2	54.9
DK/NR	15.0	23.0	38.0

5.5 Market Characteristics

Trade allies were asked a number of questions pertaining to the market for furnaces. Trade allies estimated that almost 80% of their market involves replacement furnaces. However, it should be noted that the trade allies covered in this research were those who participated in the Terasen program, and survey results pertaining to the new furnace market are not necessarily representative of the new construction market. They may be more reflective of the custom home new market.

Exhibit 5.5.1. Share of Sales Involving Replacement Furnaces

	Shares
Mean share	79.0 (4.5)
Up to 30%	11
31% to 50%	11
51% to 80%	18
81% and more	63

Note: Standard error in parentheses.

Trade allies were also asked to provide information on the composition of their furnace sales by type of furnace. Average respondent share of sales for high efficiency furnaces for new dwellings increased from 17% in 2001 to 28% in 2002 and to 37% in 2003. Average respondent share of sales for high efficiency furnaces for replacement furnaces increased from 38% in 2001 to 46% in 2002 and to 57% in 2003. This is consistent with a shift towards a more efficient furnace market. The shares of sales involving high efficiency furnaces are shown in Exhibit 5.5.2.

Exhibit 5.5.2. Share of Sales Involving High Efficiency Furnaces

	Share new dwellings (%)	Share replace-ments (%)	Weight new dwellings	Weight replace-ments	Weighted share new dwellings	Weighted share replace-ments	Overall
2001	17.2	38.4	0.21	0.79	3.61	30.34	33.95
2002	27.9	45.9	0.21	0.79	5.86	36.26	42.14
2003	37.4	56.7	0.21	0.79	7.85	44.79	52.64

Exhibit 5.5.2 also provides an estimate, albeit a biased one, of the share of high efficiency furnaces in the overall furnace market. The share of high efficiency furnaces increased from some 34% in 2001, to 42% in 2002 and 53% in 2003. For the five years 1996 to 2000, the share of condensing furnaces in Canada had stabilised at about 40 %. We believe that the share of condensing furnaces in the BC market also stabilised but at about 25% for this period. This is a significantly lower level than the national one, but it is a level consistent with the relatively low number of heating degree days in the Lower Mainland and Vancouver Island compared with much of the rest of Canada. A lower number of heating degree reduces the economic benefits of a condensing furnace.

5.6 Barriers and Opportunities

A number of questions explored trade ally perceptions of program barriers and opportunities. About 78% of trade allies felt that customers had enough information to make an informed decision on furnace choice. The two areas that were identified by respondents as requiring more information are: how much they will save on operating costs; and differences between furnaces.

Exhibit 5.6.1. Customers Have Enough Information to Make Informed Decision on Furnace Choice

	Share (%)
Base	40
Yes	78
No	23

Exhibit 5.6.2. Information customers are missing (Furnaces)

	Share (%)
Base	9
Operating costs & savings	57
Differences between furnaces	29
Time to recover investment	14
Cost to convert	14
How quiet they are	14

Similar questions were asked specifically about the furnace blower motor efficiency. The primary areas identified were to provide more information on what VSMs are, how they work, and what are the operating cost savings.

Exhibit 5.6.3. Customers Have Enough Information to Make Informed Decision on Furnace Blower Motor Choice

	Share (%)
Base	40
Yes	78
No	23

Exhibit 5.6.4. Information customers are missing (VSM)

	Share (%)
Base	9
What VSMs are and how they work	44
How much they will save	44
Time to recover investment	11
How to track power consumption	11
Heat loss calculation for their house	11

5.7 Program Design

Several issues of relevance to design of a future program were explored in the survey. The peak quarter for sales is October to December when over 50% of the furnaces for a given year are sold. If September is included, then it appears likely that over 60% of the furnaces are sold during the typical Terasen program period.

Exhibit 5.7.1. Peak Quarters for Furnace Sales

	Share of respondents Choosing this quarter
Base	40
January - March	15.3 (1.7)
April – June	12.5 (1.5)
July – September	21.8 (3.3)
October – December	50.3 (3.9)
DK/NR	3%

* Standard Error in paranthesis

Some 70% of trade allies were familiar with Energy Star furnaces as indicated in Exhibit 5.28, while 86% of those familiar with Energy Star recommend them.

Exhibit 5.7,2. Familiar with
Energy Star for Furnaces

	Share (%)
Base	40
Yes	70
No	30

Exhibit 5.7.3. Recommend
Energy Star for Furnaces

	Share (%)
Base	28
Yes	86
No	11
Sometimes / depends on customer	4

In response to a request for suggestions on how customers could be encouraged to install high efficiency furnaces, the main suggestions were: continue / expand the rebate program (38%), provide more information on HE furnaces (10%) and provide more information on energy savings (10%).

Exhibit 5.7.4. Suggestions on How Customers Could be Encouraged to Install High Efficiency

	Share (%)
Base	40
Expand / continue rebate program	38
More information on benefits of HE furnaces	10
More information on energy savings	10
Increase amount of rebate	8
Increase advertising	5
More incentives for contractors / servicing credit	5
Improve financing option	5
Reduce the cost of HE furnaces	3
No	28

A similar question was asked abut the VSMs. Primary suggestions were: provide more information about savings (20%), expand / continue the rebate program (15%), and increase advertising (10%).

Exhibit 5.7.5. Suggestions on How Customers Could be Encouraged to Install VSMs

	Share (%)
Base	40
More information about savings	20
Extend / continue the rebate program	15
Increase advertising	10
Reduce the cost of VSMs	8
Increase the rebate amount	8
Promote how quite they are	8
Provide more information about the benefits	3
Other	3
No	33

5.8 Furnace Prices

Trade allies were asked to estimate typical equipment and installed prices for a 90,000 Btuh mid efficiency furnace, a 90,000 Bthu high efficiency furnace and a 75,000 Btuh high efficiency furnace. The 75,000 Btuh furnace provides approximately the same heating capability as the 90,000 Btuh mid efficiency furnace. The results are shown in Exhibit 5.8.1.

Exhibit 5.8.1. Equipment Price and Installed Price for
90 MBtuh mid efficiency and 75 MBtuh high efficiency Furnace (2003)

	90,000 Btuh		75,000 Btuh
	Mid efficiency (dollars)	High efficiency (dollars)	High efficiency (dollars)
Base	40	40	40
Equipment price	1104 (72.8)	1806 (99.3)	1648 (139)
Installed price	2289 (109.0)	3197 (131.0)	2897 (160)

Note: Standard error in parentheses.

5.9 Free Riders and Spill Over Analysis

Trade allies were asked how important the Heating System Upgrade Program was in the customers' decisions to install a high efficiency furnace, where one was not at all important and five was very important as shown in Exhibit 5.9.1. To summarize the impact of the program, a weighted average of the importance scores was calculated, where the weights were as follows: score of five has weight of 1.00, score of four has weight of 0.75, score of three has weight of 0.50, score of two has weight of 0.25 and score of one has weight of 0.00. The weighted average of the importance scores is one minus the free rider rate of about 0.76.

Exhibit 5.9.1. Free Rider Analysis - rebate

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.45	0.28	0.18	0.05	0.05	
Product	0.45	0.21	0.09	0.01	0.00	0.76

Exhibit 5.9.2 provides a second analysis for spill over. The share of furnaces replaced early comes from the consumer survey, but the years replaced early comes from the trade ally survey. The weighted average years replaced early using this approach is 2.322 years.

Exhibit 5.9.2 Spill Over Analysis

	Replaced early (%)	Years replaced early	Weighted average years replaced early
Yes	43	5.4	2.322
No	53	0.00	0.000
DK/NR	4	-	-
Total participants	-	-	2.322

A similar set of questions was used to determine Contractors opinions of the financing program and the VSM incentive. As shown below, the weighted average of the importance scores is about 0.30 for the financing program and 0.56 for the VSM incentive.

Exhibit 5.9.3. Free Rider Analysis - financing

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.06	0.13	0.16	0.22	0.44	
Product	0.06	0.10	0.08	0.06	0.00	0.30

Exhibit 5.9.4. Free Rider Analysis - VSM

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.25	0.16	0.25	0.25	0.20	
Product	0.25	0.12	0.13	0.06	0.00	0.56

6. Impact Analysis

6.1 Furnace Fan Usage

Both Customers and Trade Allies were asked a series of questions to determine their usage of furnace fans both before and after the furnaces were replaced.

Exhibit 6.1.1 summarizes the before and after usage as reported by Customers. To facilitate comparison, the separate responses for the "heating" or the "heating and cooling" period shown in previous tables have been combined. The Before columns show the furnace fan usage by both participants and non-participants prior to replacing the furnace. The PSC and VSM columns show the response of those people who subsequently purchased furnaces with either PSC or VSM blowers. It shows that people who were using the existing furnace blower for ventilation (+6%) or for continuous ventilation (+5%), were more likely to have purchased furnaces with VSMs, and hence indicates that Customers with higher blower usage tended to move to VSMs.

The second part of Exhibit 6.1.1 shows the reported blower usage after the new furnace was installed. It shows that blower usage has increased, as the share of intermittent usage has declined from 73 to 64 while the higher usage categories have increased. However the more dramatic change is in the blower usage by people with VSMs, where intermittent usage is now 20% lower than for people with PSC motors. This indicates that VSMs are reaching the intended audience of higher furnace blower users.

Exhibit 6.1.1. Furnace Fan usage (Customer Survey)

	Before				After			
	Total (%)	PSC (%)	VSM (%)	Dif (%)	Total (%)	PSC (%)	VSM (%)	Dif (%)
Intermittent (heat / cool season)	73	73	69	-4	64	75	55	-20
Continuous (heat / cool season)	13	17	11	-6	15	13	18	+5
Also ventilation	5	2	8	+6	7	2	9	+7
Continuous	10	8	13	+5	13	9	18	+9

Exhibit 6.1.2 shows data from the Trade Ally survey. In this case the data doesn't split out VSM in the same way. The before and after data reflects all furnaces (including VSM) while VSM reflects only those new installations of furnaces with VSMs. This data shows a quite similar pattern of furnace usage before and after the installation of the new furnace. However the Trade Allies are reporting that over 50% of the VSM equipped furnaces are installed for continuous ventilation.

The discrepancy between the Customers reported usage and the Trade Ally reported usage is quite surprising, especially regarding the continuous usage. However the common pattern between the two groups is the significantly higher fan usage among people who have installed VSMs.

Exhibit 6.1.2. Furnace Fan Usage (Trade Ally Survey)

	All Furnaces		VSM
	Before (%)	After (%)	Only (%)
Intermittent (heat / cool season)	50	52	25
Continuous (heat / cool season)	14	13	18
Also ventilation	14	10	2
Continuous	22	25	55

6.2 Furnace Prices

One of the indicators of market transformation is the reduction of prices, or at least of price premiums, for energy efficient products to the consumer. Exhibit 6.2.1 reproduces the furnace pricing from the Trade Ally survey, while Exhibit 6.2.2 shows the comparable data from the 2002 survey.

The two tables appear to indicate a general price increase between 2002 and 2003. However this increase is small, and not statistically significant. Further, as the 2003 survey includes smaller firms, the data may mask higher buying power, and hence lower prices for larger firms.

Exhibit 6.2.1. 2003 Furnace Prices (Trade Ally Survey)

	90,000 Btuh		75,000 Btuh
	Mid efficiency (dollars)	High efficiency (dollars)	High efficiency (dollars)
Base	40	40	40
Equipment price	1104 (72.8)	1806 (99.3)	1648 (139)
Installed price	2289 (109.0)	3197 (131.0)	2897 (160)

Note: Standard error in parentheses.

Exhibit 6.2.2. 2002 Furnace Prices (Trade Ally Survey)

	90,000 Btuh		75,000 Btuh
	Mid efficiency (dollars)	High efficiency (dollars)	High efficiency (dollars)
Equipment price	1068 (52.0)	1596 (105)	1504 (116)
Installed price	2194 (81)	3121 (115)	3071 (129)

Note: Standard error in parentheses.

From the perspective of market transformation, a key issue is the incremental cost of installing the efficient product. As the output of a 90,000 BTU mid efficiency furnace is essentially the same as the output of a 75,000 high efficiency furnace, this is the relevant comparison. Exhibit 6.2.2 shows the change in incremental cost to install a high efficiency furnace in 2003 vs. 2002, and shows that the incremental cost has dropped by 30% over the two years. Assuming a current natural gas price of $ 12.35 per GJ, and an energy reduction of 12.6 GJ per year, this approximates a payback of 5.6 years in 2002 dropping to 3.9 years in 2003.

Exhibit 6.2.3. Comparison of Installed Furnace Prices

	90,000 Btuh Mid efficiency (dollars)	75,000 Btuh High efficiency (dollars)	Incremental Cost (dollars)
Installed price - 2003	2289	2897	608
Installed price - 2002	2194	3071	877

6.3 Impact of Secondary Heating on Natural Gas Savings

The Customer survey determined that, after the new furnace was installed, about 5% of program participants increased their use of secondary heating while about 47% reduced the secondary heating, and the reduction was by about 50%. The concern is whether this change in the use of secondary heating is affecting the billing analysis estimates of program savings. For example, if more of the space heating load is shifted to the furnace by a reduction of non-natural gas fueled secondary heating, then the billing analysis may understate the impact of the program.

The Customer survey determined that 66% of the secondary heating is from natural gas, 28% from electricity and 19% from wood[5]. Further, 70% of the natural gas secondary heat is from fireplaces. If we make the following assumptions, then we can estimate the net impact of the change in secondary heating on overall natural gas usage.

- The consumption of a natural gas fireplace is about 16 GJ per year (2002 REUS).
- The equivalent AFUE of the average natural gas fireplace is about 50%.
- Electric and wood secondary heat provide the same proportion of total space heat as the natural gas secondary heat (ie: 16GJ @ 50% efficiency or 8GJ of output heat)
- Those who increased secondary heating usage (5%) had approximately the same consumption as those who decreased usage (47%), for a net reduction of 42%.

Exhibit 6.3.1. Change in Natural Gas Consumption from Secondary Heating

	Output Energy (GJ)	Share Secondary Heat (%)	Net Output Energy (GJ)	Furnace Input Energy (AFUE 92) (GJ)	Share Secondary Heat	Unit Impact (GJ)
Electric	8	28	+2.24			
Natural Gas	8	66	-5.28			
Wood	8	19	+1.52			
Total			-1.52	-1.66	0.42	-0.70

As shown in Exhibit 6.3.1, the potential impact from the reduction in secondary heating after the installation of the high efficiency furnace appears small, in the order of -0.7 GJ per year. Given the significant assumptions required for this analysis, it was concluded not to include any impact from secondary heating in the program impacts.

6.4 Program Attribution – Discrete Choice

In many program evaluations, program impact is measured as the difference between outcomes for a treatment group (or set of program participants) and a control group (or set of program non-participants). Program impact is then estimated by the "difference of differences" approach where estimated impact is defined as average participant change minus average non-participant change. Here the underlying assumption is that the non-participant change estimates the change that the participants would have experienced on average in the absence of the program[6]. This method works best if there is random assignment to the

[5] The data in Exhibit 4.4.3 has been adjusted for the reporting of multiple responses.

[6] This methodology, while commonly used in DSM program evaluations does not

treatment and control groups, as is often the case in medical and social experiments.

In DSM evaluations random assignment to treatment and control groups is very difficult. For example, participation in the Residential Heating System Upgrade Program is voluntary so that there is potentially an element of self-selection involved. Self-selection in this context means that those who participate in the program may be more likely than average to install energy efficient measures than the average person even in the absence of the program.

There are two main ways of dealing with self-selection: the survey approach and the discrete choice theory approach. In the survey approach, a sample of participants is asked how likely they would have been to install the efficient measure in the absence of the program. Sometimes, responses are weighted to provide an estimate of the free rider rate. However, this method may result in inaccurate estimates because respondents may assume they would have purchased the efficient technology without the program in place, even though this may not be the case. Respondents may also give answers that they think the interviewer wants to hear. Further, respondents are often not conscious of all the factors that lead them to make a specific purchasing decision. Therefore, too much or too little emphasis may be given to the program, when in fact other variables may have played a key role in influencing customer behavior.

Many of these problems can be minimized by using discrete choice analysis (DCA) to estimate program attribution. DCA enables the attribution rate to be estimated based on objective data (explanatory variables), instead of the subjective responses of customers. In DCA, probit or logit regression methods are typically used to estimate the probability of purchasing an efficient technology based on key explanatory variables. Data is collected on customers' observed purchasing behaviour as well as on several explanatory variables. Then probit or logit regression is used to estimate an equation that relates the observed purchasing behaviour to the explanatory variables. This probit or logit equation can then be used to predict the probability that a customer will purchase an efficient technology based on the levels of the explanatory variables for that customer. This approach was used to estimate the attribution to the furnace program.

Model 1: Choice to participate in the high efficiency furnace program

In modeling the determinants of participation in the high efficiency furnace

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consider that, in the case of a furnace replacement program, the customer would likely purchase a new furnace in the near future (when the existing unit failed). As the minimum furnace standards were increased in 1995, the new furnace would be more efficient than the existing unit, but not necessarily as efficient as the program induced unit. This issue cannot be addressed purely in a billing analysis as data on the remaining life of the furnace at the time it was replaced is required. This information was available from the survey work done to support the 2003 programs, and is included in this report.

program, the relevant literature suggest that key determinants of the decision to participate might include the amount of energy consumed prior to the program period, attitudes towards energy efficiency, and attitudes towards heating system costs. We also considered income, size of the home, and other variables that proved to degrade the statistical fit of the model. This suggests the model shown in (1) which we model using a probit equation, where households are indexed by the subscript i.

(1) $\text{program participation}_i = f(\text{consumption}_i, \text{importance\_EE}_i, \text{importance\_cost}_i)$

The variables are defined as follows:

- *program participation* takes the value "1" for program participants and "0" for program non-participants;
- *consumption* is the weather normalized annual consumption prior to the program period;
- *importance_EE* is the importance of energy efficiency on the household's choice of heating system (measured on a scale from 1 to 5);
- *importance_cost* is the importance of the total system cost (initial plus operating) on the household's choice of heating system (measured on a scale from 1 to 5).

Model 2: Choice to install a high efficiency furnace

In modeling the determinants of installation of a high efficiency furnace, the relevant literature suggest that key determinants of the installation decision might include program participation, the amount of energy consumed prior to the program period, attitudes towards energy efficiency, and attitudes towards heating system costs. We also considered income, size of the home, and other variables that proved to degrade the statistical fit of the model. This suggests the model shown in (2) which we model using a probit equation, where households are indexed by the subscript i.

(2) $\text{high install}_i = g(\text{program participation}_i, \text{consumption}_i, \text{importance\_EE}_i, \text{importance\_cost}_i)$

The variables are defined as follows:

- *high install* takes the value "1" for those installing a high efficiency furnace during the program period and "0" otherwise;
- *program participation* is a dummy variable that takes on the value "1" for participants and the value "0" for non-participants;
- *consumption* is the weather normalized annual consumption prior to the program period;
- *importance_EE* is the importance of energy efficiency on the household's choice of heating system (measured on a scale from 1 to 5);
- *importance_cost* is the importance of the total system cost (initial plus operating) on the household's choice of heating system (measured on a scale from 1 to 5).

RESULTS

Model 1: Choice to participate in the high efficiency furnace program
As noted above, we model the determinants of program participation in the high efficiency furnace program as a function of the weather normalized annual consumption prior to the program period, attitudes towards energy efficiency, and attitudes towards heating system costs (equation 1). This equation was estimated using a probit model. The model was fit using weighted data to correct for the over-representation of program participants in the customer survey sample.[7]

Exhibit 6.4.1 shows the results of the probit regression. For each variable the values of the coefficient, the standard error, the t-statistic and the partial effect are shown, where the partial effect measures the change in the probability of participation due to a one unit change in the independent or driving variable. Also shown are the chi-squared statistic and the share of outcomes correctly predicted by the model, which are measures of goodness of fit for non-linear equations like the probit.

The model fit is good with 51.0% of the outcomes correctly predicted. Increases in pre-program consumption, importance of energy efficiency, and importance of total system cost all lead to an increase in the probability of program participation.

Exhibit 6.4.1. Determinants of Program Participation

	Coefficient	Standard Error	T-statistic	P-Value	Partial Effect
Constant	-.67	.103	-6.47	.00	-.197
Consumption	.00056	.00029	1.93	.053	.00017
Importance_EE	.00030	.00074	.41	.68	.00009
Importance_Cost	.00036	.00051	.70	.49	.00010
Chi-squared [3 df]	7.14			.068	
Share Correct (%)	51.0%				

Model 2: Choice to install a high efficiency furnace
We model the determinants of installation of a high efficiency furnace as a function of program participation, weather normalized annual consumption prior to the program period, attitudes towards energy efficiency, and attitudes towards heating system costs (see equation 2). This equation was estimated using a probit model. The model was fit using weighted data to correct for the over-representation of high efficiency furnace installations in the customer survey

[7] 49% of households in the customer survey were program participants. In comparison, only 23% of households in the total 2003 retrofit market were program participants (assuming approximately 13000 total furnace installations and 2915 total program participants). Therefore, the survey data were weighted to correct for the unrepresentative nature of the sample.

sample.[8]

Exhibit 6.4.2 shows the results of the probit regression. The model fit is good with 80.3% of the outcomes correctly predicted. Households who participated in the program were much more likely to purchase a high efficiency furnace than those who did not participate. Additionally, increases in pre-program consumption and importance of total system cost lead to an increase in the probability of purchase of a high efficiency furnace; while an increase in importance of energy efficiency leads to a decrease in the probability of purchase of a high efficiency furnace. Note however that the coefficients on pre-program consumption, importance of energy efficiency, and importance of total system costs are not statistically significant.

For our purposes, the most important information in the table is the partial effect on the participation variable because this gives us the net to gross ratio. The net to gross ratio is the share of purchases of high efficiency furnaces attributable to the incentive program. The net to gross ratio is 72.3%, which says that about 72% of purchases of high efficiency furnaces during the program period are actually attributable to the incentive program. In perhaps more familiar terms, this means that the net effect is 72% and the free rider rate minus the spill over rate is 28% (using the expression, net effect = gross effect minus free rider rate plus spill over rate).

Exhibit 6.4.2. Determinants of Furnace Choice

	Coefficient	Standard Error	T-statistic	P-Value	Partial Effect
Constant	-.58	.13	-4.38	.00	-.0048
Participation	8.24	.13	63.56	.00	.723
Consumption	.00011	.00030	.36	.72	.00000
Importance_EE	-.00025	.00068	-.37	.71	.00000
Importance_Cost	.00012	.00054	.23	.81	.00000
Chi-squared [4 df]	132.71			.00	
Share Correct (%)	80.3%				

6.5 Energy Savings and Peak Reduction

To estimate energy savings, unit savings are multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio to provide the estimate of net savings.

Two sources of information were used for this analysis. The first was data from the customer survey, the second from the trade ally survey. The differences

[8] 69% of households in the customer survey installed a high efficiency furnace. In comparison, only 57% of households in the total 2003 retrofit market installed a high efficiency furnace (based on results from the trade ally survey). Therefore, the survey data were weighted to correct for the unrepresentative nature of the sample.

between the data are that the customer survey indicated a different period of time for early replacement. It was felt that the trade ally survey provided better information on the remaining life of the furnace, due to the greater expertise of the trade relative to homeowners, and this estimate has been used in the report.

Three approaches to determining program attribution were considered, (1) responses to customer survey questions, (2) responses to trade ally survey questions, and (3) the Discrete Choice approach discussed in the previous section. These different approaches provided an attribution of 57% from the Customer survey, 76% from the Trade Ally survey and 72.3% from the Discrete Choice analysis. The Discrete Choice estimate was used as this approach is typically less biased and better reflects the impact of the overall program rather than just the incentive component. Estimated net savings are 37.4TJ for the first 5.4 years and 26.6TJ for the subsequent years.

Exhibit 6.5.1. Energy Savings – customer survey

	Unit savings (GJ)	Gross participants	Gross savings (TJ)	Net to gross ratio	Net savings (TJ)
Direct	12.60	2,915	36.729	0.723	26.555
Spill over	8.68	1,253	10.876	1.000	10.876
Annual - first 5.4 years	-	-	-	-	37.431
Annual - subsequent years	-	-	-	-	26.555

In order to estimate peak savings, we assume that heating load on any day is proportional to heating degree days for that day, so that in the coldest month (January) the average daily heating load is (annual heating load in GJ)*(monthly share of annual heating degree days for January)*(1/31 days). The change in peak day load is then estimated as the change in average daily load for January. Exhibit 6.6 calculates the weighted peak day heating load share for January using a representative weather station for each zone and the thirty-year typical meteorological year heating degree-day shares for January. Estimated peak day savings is then weighted peak day heating load share for January multiplied by net savings. Estimated peak day savings are 0.20TJ for the first 5.4 years and then 0.15TJ for subsequent years.

Exhibit 6.5.2. Peak Day Savings

Zone	Representative weather station	Zone customer share	Peak day heating load share	Weighted peak day heating load share	Peak day savings first 4.5 years (TJ)	Peak day savings subsequent years (TJ)
Zone 1	Vancouver	0.244	0.00501	0.00122	-	-
Zone 2	Burnaby	0.173	0.00511	0.00084	-	-
Zone 3	Surrey	0.280	0.00510	0.00143	-	-
Zone 4	Kamloops	0.117	0.00625	0.00073	-	-
Zone 5	Cranbrook	0.186	0.00667	0.00124	-	-
Total		1.000		0.00546	0.2044	0.1450

6.6 Carbon Dioxide Reductions

Natural Resources Canada and Terasen Gas use emissions factors of 50.45 tonnes of carbon dioxide per terajoule and 50.00 tonnes of carbon dioxide per terajoule respectively. Exhibit 6.7 shows the reductions in carbon emissions under the assumption of an emissions factor of 50 tonnes per TJ.

Exhibit 6.6.1. Carbon Dioxide Emissions Reductions

	Net savings (TJ)	Emissions factor	CO_2 reductions (ktonnes)
Direct	26.555	0.05000	1.3278
Spill over	10.876	0.05000	0.5438
Total first 5.4 years	37.431	0.05000	1.8716
Total subsequent years	26.555	0.05000	1.3278

7. Conclusions

Conclusion 1: customer and trade ally satisfaction with the program:

Maintaining high levels of customer satisfaction is a key concern of program management and staff. Satisfaction with a variety of program components was rated on a five-point scale where one is not at all satisfied and five is very satisfied. Participants reported satisfaction levels averaging 3.8 or more for application procedures, information on the rebate, information abut efficient furnaces and types of furnaces eligible for the rebate. Lower levels of satisfaction were expressed for the time period of the program and the amount of the rebate, but these are 3.7 and still quite positive. Trade Allies reported satisfaction of 3.8 or higher for the amount of the rebate, types of furnaces eligible for a rebate, information on the rebate and application processing. The program has achieved high levels of customer and trade ally satisfaction.

Conclusion 2: impact of marketing / advertising of program:

Advertising and promotional activities are a key means of increasing program awareness and participation. For participants and non-participants, the main sources of awareness are: the insert in the Terasen Gas bill, the heating contractor and word of mouth. However, with the exception of bill inserts, these sources of awareness are all quoted at lower levels by non-participants. Compared with the 2002 evaluation, awareness of the program by non-participants has declined from about 41% to 31%. At the same time it appears that the demographics of non-participants have also changed. In 2003 over 68% of the non-participants were age 55 and over whereas in 2002 only 50% fell into this category. This shift in demographics may indicate a need for different strategies to reach the older age groups. A second possible cause for the decline in awareness is that in 2002, the Furnace Tune-up program had 45,000 participants which may have generated broader awareness of all Terasen programs.

Conclusion 3: effectiveness of financing vs rebates as incentives:

The 2003 program included a finance option for the first time. Analysis of program records indicates that only 211 of the 2,915 participants, or about 7%, took advantage of the option. However 57% of these people, or 120 participants indicated that, without the financing option, they would not have purchased a new furnace at this time. Therefore it can be concluded that the finance option increased the program sales by about 4%, or about the total increase in sales between 2002 and 2003.

Conclusion 4: installed prices of mid and high efficiency furnaces (HEF):

One of the indicators of market transformation is the reduction of prices, or at least of price premiums, for energy efficient products to the consumer. While there is some indication of a general price rise for all furnaces between 2002 and 2003, there also appears to have been a decrease in the incremental installed price of a high efficiency furnace relative to a mid efficiency furnace. The incremental price has dropped from $877 to $608, or about 30%. This is the equivalent of a reduction in payback period from 5.6 years in 2002 to 3.9 years in 2003.

Conclusion 5: program impact on sales of high efficiency furnaces:

Three approaches to determining program attribution were considered, (1) responses to customer survey questions, (2) responses to trade ally survey, and (3) the Discrete Choice approach discussed in the previous section. These different approaches provided an attribution of 57% from the Customer survey, 76% from the Trade Ally survey and 72.3% from the Discrete Choice analysis. The Discrete Choice estimate was used as this approach is typically less biased and better reflects the impact of the overall program rather than just the incentive component.

Conclusion 6: program impact on sales of variable speed blower motors (VSM):

Impact of the program on sales of VSMs is less clear than for high efficiency furnaces. Both Customers and Trade Allies were asked about the importance of the program in their choice of furnace with VSM. The Customers' survey indicated an attribution rate of 61% to the program while the Trade Allies indicated a lower rate of 50%. However a comparison of adoption rates between participants and non-participants showed an increase in sales to participants of about 41%.

Conclusion 7: usage of furnace blowers before and after the furnace replacement:

Customers and Trade Allies were queried about the use of their furnace blowers before and after the installation of the new furnace. Analysis of the Customer data shows that people who were making use of the furnaces to provide various levels of ventilation (ie: not just when the system is providing heating or cooling) were more likely to buy a furnace with a VSM. Data on blower usage after the furnace was installed shows that usage of the blower only when providing heating or cooling declined from 73% to 64% with more intensive uses of the blower increasing by a similar amount. However most of this increased blower usage is going to furnaces with VSMs. For example, when comparing blower usage before the furnace installation with just those people who installed VSMs the usage when only providing heat or cooling declines from 73% to 55%. The Trade Ally data confirms these trends, but shows an even stronger shift to continuous ventilation.

Conclusion 8: change in the use of secondary heating after installation of HEF furnace:

The Customer survey determined that 42% of participants decreased their use of secondary space heating after installing the new furnace while only 5% increased their usage. If the fuel is other than natural gas, a reduction in secondary heating will increase the load on the furnace. However if the secondary heating fuel is natural gas, and the secondary heating source is less efficient that the furnace, a reduction in secondary heating will increase the natural gas savings as the load is picked up by the more efficient furnace. The potential impact from the reduction in secondary heating after the installation of the high efficiency furnace appears small, in the order of -0.7 GJ per year. Given the significant assumptions required for this analysis, it was concluded not to include any impact from secondary heating in the program impacts.

Conclusion 9: determinants of HEF program participation:

The discrete choice analysis for the overall furnace program found that the primary determinants of program participation were: consumption of natural gas; importance of energy efficiency and importance of costs. This is also reflected by survey questions on the importance of various influencers on heating system choice (measured on a 5 point scale) which included: energy efficiency (4.5); comfort (4.4); and operating cost (4.3).

Conclusion 10: determinants of VSM incentive participation:

The primary drivers for participation in the VSM incentive component of the program were: energy efficiency (49%); contractor recommendation (23%); quieter operation (10%) and wanting continuous ventilation (10%).

Conclusion 11: discrete choice based estimates of energy savings:

To estimate energy savings, unit savings are multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio. Estimated net savings are 37.4TJ for the first 5.4 years and 26.6TJ for subsequent years. Estimated peak day savings are the weighted peak day heating load share for January multiplied by net savings. Estimated peak day savings are 0.20TJ for the first 5.4 years and then 0.15TJ for subsequent years.

Conclusion 12: discrete choice based estimates of carbon dioxide reductions

Using an emissions factor of 50 tonnes of carbon dioxide per terajoule yields an emissions reduction or carbon dioxide savings of 1.87 kilotonnes of carbon dioxide for the first 5.4 years of the program and 1.33 kilotonnes of carbon dioxide for subsequent years of the program.

Conclusion 13: status of market transformation in the BC furnace market:

Two indicators of market transformation are considered in this evaluation, changes in market share of high efficiency furnaces over time and changes in customer payback, with increasing market share and improving payback being considered as indicators of market transformation.

- Market share of high efficiency furnaces in the retrofit segment has increased from about 38% in 2001 to about 57% in 2003 while the estimate of the overall market served by Trade Allies included in the study has increased from 29% to about 52%.

- Based on typical furnace prices provided by the Trade Allies, it appears that the incremental cost of installing an high efficiency furnace relative to a mid efficiency furnace has dropped between 2002 and 2003, with a reduction in payback period to the customer dropping from 5.6 years to 3.9 years.

These indicators suggest that the program has made substantial progress in transforming the market for furnaces in B.C.

Appendix A – Weather Normalization Methodology

The weather normalization of the billing data used for this project was developed by Terasen Gas. This description of the weather normalization process was provided by Mr. Lee Robson of Terasen Load Forecast Group.

When normalizing consumption with respect to weather for Rate 1 customers, the following methodology is followed:

1. Obtain consumption history, ensuring at least twelve months consumption is available per period (period being "pre" and "post" installation periods). This provides a number of read dates, consumption and the number of days over which consumption occurred. The consumption figures are converted so that they provide an average daily consumption (total consumption / read days = average consumption).

2. Obtain the HDD's (Heating Degree Days – both using a 13 degree and 18 degree heating day) covering the entire period in question. The average HDD's (both 13 and 18) are matched to the dates in (1), to provide both average consumption and average HDD's.

3. Run the following regression model:

   AvgConsumption = Alpha + (Beta1 X AvgHDD13) + (Beta2 X AvgHDD18) + Error

4. The parameters Alpha, Beta1, and Beta2 from the above regression are then applied to the total HDD's (13 and 18) that would be experience during a "normal" year (which is basically the average of the HDD's over the past 10 years), and this results in a "normalized consumption". The actual formula applied to the parameters calculated in (3) is:

   Normal Consumption = (365 X Alpha) + (TotalHDD13 X Beta1) + (TotalHDD18 X Beta2).

Appendix B – Billing Data Screening

This description of the billing data screening process was provided by Mr. Lee Robson of Terasen Load Forecast Group.

For each premise, consumption information is obtained for a period of 500 days both prior to and after the installation date.

Using the bi-monthly meter reads (and associated consumption), the average daily consumption per meter read is determined. The average daily HDD13 and HDD18 for that same period is also determined. Then run the following regression model is run:

Average Daily Consumption = B0 + (B1 X HDD13) + (B2 X HDD18)

The total HDD13's and HDD18's during a "normal" year (basically the average of the past ten years) are determined and a normalized annual consumption is calculated by:

Normal Consumption = (365 X B0) + (TotalHDD13's X B1) + (TotalHDD18's X B2)

The above calculations are performed on the "pre" and "post" consumption separately.

The following elimination criteria are then applied which provides the finalized list:

1. Only keep those customers that have been in the same premise for at least one year prior to and after the installation date.
    - As different customers have different consumption requirements, a bias would be introduce bias if this screen wasn't used.

2. Only keep those customers where the regressions give an R-Square value > 75%
    - This ensures the model (consumption as a function of heating degree days, both 13 and 18) is a good fit – a value of 75% or greater implies that ¾ of the variation in the model is explained by the model.

3. Only keep those customers where the heatslope coefficient is positive (HDD18)
    - As customers should consume more gas as the heating degree days increase, this screen removes those customers that show less consumption as heating degree days increase.

4. Only keep those customers who have an actual annual consumption > 30GJ

- The average heating load for a Terasen customer is 68 GJ (2002 REUS). This screen eliminates customers who would appear to be using natural gas only for non-heating uses or as secondary heat.

5. Only keep those customers where the EDF (Error Degrees of Freedom) > 3 (which means we have at least five meter reads for that customer)
   - This filters out suspect meter reads, which are meter reads where the transaction period refers back to a date prior to the last read date output (ie. The read date less the corresponding read days is before the last read date). Meter reads are also filtered out where the consumption is zero. For at least one years' worth of consumption, there should be at least 6 meter reads – therefore this screen basically ensures we haven't skipped over more than one meter read.

6. Only keep those customers where the weather effect is less than 2 standard deviations away from the average weather effect. The weather effect is defined as:

Weather Effect = (Normal Consumption – Actual Consumption) / Actual Consumption

   - This basically filters out the outliers – since 96% of all data is within two standard deviations of the mean, this simply eliminates those with abnormally large weather effects.

The final step is to match those customers in the "pre" analysis with those in the "post" analysis

1. TRIPLE POINT PROJECT

The Terasen Gas measurement technologies group, has developed a method of testing high pressure meters (internally referred to as "Triple Point") using Carbon Dioxide ("$C0_2$") in a closed loop at pressures up to 16 bar. The design of the process will deliver superior calibration data for turbine meters used in high pressure natural gas applications at reduced cost, faster response, and enhanced safety over currently available processes. This is a departure from the current standard measurement process using Natural Gas and as a result, patents have been filed in Canada, the United States and the European Union.

Terasen Gas' current practice is to send its meters to an external measurement testing facility at a cost between $4,000 and $8,000 per meter depending on the meter capacity. The number of facilities capable of providing this testing is limited at present due to the very high cost of construction, operating criteria required, operating costs, and safety considerations. As a consequence, testing is expensive and long delays in scheduling tests are not uncommon. By using the Triple Point process, Terasen Gas can provide a meter testing service at costs substantially below that of other providers with a much faster turn around time. Terasen Gas therefore plans to test meters for external customers as well as its own meters.

Process

The Triple Point process will add a second test loop in addition to the existing low pressure air loop at the Penticton, BC facility run by Terasen Gas Measurement Technologies. Carbon dioxide storage and handling systems will be installed. The loop is composed primarily of pressurize piping in 100mm through 300 mm sizes and fluid compression/moving equipment. The scope of construction and size of plant is similar to the current turbine plant.

Meters to be tested will be placed into the loop and a series of flow calibrations will be performed using computer managed programs. The process will be automated, safe, reliable and fast. Carbon Dioxide for the process has been sourced from a supplier who extracts the product from the atmosphere ensuring no net gain of greenhouse gasses from the project. The loop is closed and only small amounts of Carbon Dioxide are vented to the atmosphere from the loop during testing.

Market

The market for Triple Point services is comprised of the Terasen Gas family of companies, other British Columbia utilities and industrial clients, utilities across Canada, and all categories of meter users in the United States. For the utility sector only, the annual projected potential for turbine meter tests in North America, referencing emerging regulations and the scope of Triple Point services, is over 6,000. This is made up of meters in service in utility companies at pressures over 1 bar[1] and less than 4 bar, and meters in utility and transmission companies in service at pressures in excess of 4 bar, all of a size between 100mm and 300mm.

Forecast capture rate for the first 5 year period is anticipated to be 35% of the firm market, 15% of the over 4 bar optional market and 5% of the under 4 bar optional market. Growth in meter populations is estimated at 2%. To confirm the capture rates, a comprehensive independent market study was undertaken to assess and verify all aspects of the Triple Point market capture, growth and service pricing. The independent market study validated the Terasen Gas findings.

Business Opportunity

While Terasen Gas will see cost savings from testing its own meters, these savings do not fully offset the incremental revenue requirement attributable to the new facility. Terasen Gas must therefore test external meters to make the project viable. Terasen Gas is evaluating two options to implement the Triple Point Business Project.

Option One

Terasen Gas is exploring the possibility to partner with Terasen Utilities Services ("TUS") to market and sell the Triple Point Measurement Service to North American Customers external to Terasen Gas. In this model, TUS would be responsible for marketing and selling the product, and Terasen Gas would be responsible for the actual measurement testing procedure.

[1] a unit of pressure equal to 100,000 pascals or to one million dynes per square centimeter or to 0.9869 atmosphere

The agreement would be based upon the following parameters:

- 5 year contract between Terasen Gas and TUS with a 5 year renewal option
- Terasen Gas to provide start-up Capital Expenditures for the new facility
- Terasen Gas to provide meter testing and calibration services (internal and external)
- TUS to provide marketing services
- TUS to set the retail market price for meter services
- Annual sales quotas will be established and the arrangement would be cancelable at Terasen Gas' option should targets not met
- TUS to receive revenues from meter testing
- TUS to pay Terasen Gas the wholesale market rate that is intended to recover the fully allocated cost of service for each meter tested plus a profit percentage
- A non-rate base deferral account to be established to record the revenue requirement associated with the capital investment, as well as revenue and expenses incurred in the operation of the business.

Terasen Gas customers will benefit from the reduction in operation and maintenance ("O&M") costs of approximately $200,000 per year associated with current practice of external meter testing under this option. Terasen Gas and its customers will also benefit more quickly if TUS sells more meter testing procedures than originally forecast since TUS will be incented to meet and exceed annual sales quotas.

<u>Option Two</u>

Terasen Gas would market and sell the Triple Point Measurement Testing service "in house". Terasen Gas would be responsible for finding customers and selling them on the benefits of the Triple Point Measurement Service. Terasen Gas would price the service at a competitive market rate. Terasen Gas would test its own meters which will benefit all customers because of an expected reduction in annual O&M costs of approximately $200,000 versus the current practice of outsourcing meter testing.

Under both Options, Terasen Gas believes that this new service would provide a long term benefit to the core customer by providing incremental revenue. However, Terasen Gas believes that the business will require a separate regulatory construct and as such, Terasen Gas proposes that:

- the business remain separate from the current PBR due to the length of time required to recoup the initial investment
- a non-rate base deferral account (attracting AFUDC) be established to record the revenue requirement associated with the new capital investment and variable costs of meter testing, mitigated by revenues from testing meters. This proposed deferral account will have a ten years term and once the account is in a net credit position, surpluses will be shared between shareholders and customers.

Terasen Gas will be submitting an application to the Commission for review and approval as soon as it has determined the appropriate option to recommend.

2. UTILITIES STRATEGIES PROJECT – STATUS UPDATE

The integration initiative, referred to internally as the Utilities Strategies Project ("USP"), commenced September 6, 2003 with the planning and organizational design work completed by the end of October 2003. A staffing process was completed in November and on December 12th, 2003 a new organization structure was announced. To ensure that the company maintained its focus on safe and reliable service to our customers a number of guiding principles were employed in carrying out the project:

- Business process teams evaluated current business processes and selected the best practice process solutions.
- Staffing process enabled the retention of the best people from both organizations.
- Key employees who selected early retirement were retained for a period of time in 2004 to allow knowledge transfer.
- The business approach and IT platforms were standardized.
- Conversion costs of historical data were minimized while maintaining retrieval capability.
- Separate legal entities, rate bases and rate design were maintained.
- Cost efficiencies flowed to both entities' customers according to their separate regulatory frameworks.
- Cost driver information was captured to ensure proper allocation of costs and savings.
- Common compensation practices for all employees were developed.

The integration allowed a shared service approach that enabled both companies to harness the benefits from economies of scale by having a single management and support structure that avoids duplication of work and allows customers to benefit from the synergies created. As a result of the restructuring initiative, TGI and TGVI incurred onetime restructuring charges of approximately $15.5 million due to having 115 fewer employees. TGI and TGVI's respective share of the restructuring costs are expected to be $11.3 million and $4.2 million. Additionally, TGI and TGVI have realized savings of approximately $8.0 million and $2.5 million in 2004 excluding restructuring costs. For 2005, the anticipated net savings are expected to be approximately $10 million in total for the two utilities after giving effect for the additional revenue requirement resulting from capital investments at TGVI. The resulting total cumulative savings over the 2004/2005 period is expected to be $20.4 million, $4.9 million greater than the $15.5 million restructuring charges, and ongoing benefits of approximately $10 million/year, to be shared with customers according to the respective negotiated rate settlements of the two utilities.

Beyond this short payback period, customers of both utilities have and will enjoy the benefits of lower costs in the future as a result of the operational integration undertaken. To achieve these benefits capital investments totaling approximately $8 million are required by TGVI in the 2004/2005 period to allow for a shared information technology platform. Approximately $3.0 million has been spent on the shared platform for the Back Office Business System, Geographical Information System and common infrastructure. Work is continuing on the Order Fulfillment System, Meter Management and Mobile System. These systems require interfaces to the customer billing system and that work is waiting on the resolution of the Banner to Energy decision.

As part of the integration, the Company is considering the conversion of TGVI's customer information system (Banner), which is currently outsourced to Enlogix, to the Energy system used by TGI. The customer care function of TGVI including billing and call handling will likely be contracted with Accenture Business Services for Utilities (ABSU) if the conversion takes place. A feasibility study in now being completed but the timing and projected cost of the conversion and related benefits are not know and have not been included in this report.

3. SHARED SERVICES MANAGEMENT AGREEMENT

On May 31, 2004, Terasen Gas and Terasen Gas (Vancouver Island) Inc. (TGVI) filed with the Commission a Shared Services Management Agreement which provided details of the restructuring initiative and derivation of the annual allocated shared services cost as a result of the operational integration of Terasen Gas and TGVI. Subsequently, on October 20, 2004, Terasen Gas submitted a proposal to the Commission to deal with some income tax matters that have arisen relating to transferring of assets. Both of these documents are contained in Appendix A to Section B-4.

SECTION B-4 MATERIAL EFFICIENCY MEASURES

ATTACHMENT A – UTILITIES STRATEGY PROJECT UPDATE

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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October 20, 2004

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

Attention: Mr. Robert J. Pellatt, Commission Secretary

Dear Sir:

**RE: Terasen Gas Inc. and Terasen Gas Vancouver Island
Shared Services Management Agreement - Update**

On May 31, 2004, Terasen Gas Inc. (TGI) and Terasen Gas Vancouver Island (TGVI) filed with the Commission a Shared Services Management Agreement providing details of the restructuring initiative and derivation of the annual allocated shared services cost as a result of the operational integration of TGI and TGVI. At the time of the filing, it was noted that the integration requires TGVI to make capital investments totaling some $8 million in 2004/2005. As well, TGI was to transfer to TGVI $2.4 million representing a 10% interest in the net book value of the SAP technology platform assets to preserve the nature of the costs associated with the rate base of the assets as they are utilized.

Since the filing, some income tax complications have surfaced with the proposed asset transfers. To alleviate these complications, TGVI looked at various other options from notionally transferring the assets for rate setting purposes to setting up some form of management fee in lieu of the notional asset transfer. Based upon the findings, it appears the optimal solution is for TGVI to include in its annual revenue requirement an operating lease expense equivalent to the revenue requirement associated with ownership of the assets had the asset transfer taken place. The operating lease expense would be categorized similar to rent for the compressor lease equipment so TGVI would not be adversely impacted by the negotiated settlement O&M mechanism. For 2004, this amount is estimated to be $451,000. Details behind the proposed 2004 operating lease expense can be found in Appendix A.

In summary, the recommended proposal is for the assets to reside in the books of TGI, consistent with the common shared technology platform theme, and TGVI will reimburse TGI for the use of the assets as an operating lease at a rate equivalent to ownership of the assets had the asset transfer taken place.

Should you have any questions or comments, please contact the undersigned at 604-592-7784.

Yours very truly,

TERASEN GAS INC.

Original signed by:

Scott Thomson

Encl.
c. 2004-2007 NSP Intervenors

APPENDIX A

TGVI Revenue Requirement Impact ($000)

		2004
Rate Base		
FOY	$	2,380
Additions		-
CIAOC		(792)
Depr		(298)
Amort of CIAOC		99
EOY	$	1,390
Mid - Year	$	1,885
Cost Component of Capital Structure		
Short-Term		0.57%
Long-Term		2.92%
Common		3.33%
		6.82%
Revenue Requirement Impact to TGVI		
Higher Rate Base	$	162
Depreciation (Grossed up for Income Tax)		303
Tax savings -hardware		(13)
	$	451

Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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May 31, 2004

British Columbia Utilities Commission
Box 250
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Mr. R.J. Pellatt

Dear Sir:

Re: Terasen Gas Inc. and Terasen Gas Vancouver Island
Shared Services Management Agreement

During the regulatory rate setting process for test years 2003 and 2004, Terasen Gas Inc. indicated that the acquisition of Centra BC (TGVI) and Centra Whistler would provide an opportunity to create synergies. A number of synergies were identified and reflected in 2003 revenue requirements and by formula into the 2004 rates of Terasen Gas Inc. (TGI). Similarly, savings accruing to TGVI were included in its revenue requirement filing in the fall of 2003.

TGI and TGVI have now undertaken a major restructuring initiative which will deliver substantial savings for the two companies. A single management team is now in place and common work processes and information technology platforms are being developed and implemented to create a more cost effective and sustainable support organization. The operational integration of TGI and TGVI require significant upfront investments in process changes and organizational restructuring. Capital investments totalling some $8 million are expected to be incurred to harmonize the information technology platforms including the transfer of a 10% interest ($2.4 million) in the net book value of the SAP platform of TGI. In total, $15.5 million have or will be incurred on restructuring, resulting in a net staff reduction of 115 employees. These upfront investment costs are expected to generate sustainable annual savings exceeding $10 million per year between the two companies.

With a single management and support team, services will be delivered on a shared basis. Utilizing a framework similar to that used by Terasen Inc. to allocate corporate centre management fees to TGI, an allocated shared services cost for the provision of shared services to TGVI is estimated to be $2.8 million for 2004. This annual allocated shared services cost will be trued up at year end when actual shared costs are known. TGVI and its customers are expected to realize net annualized benefits of approximately $2.0 million once all costs including shared service cost allocations are factored in. Terasen undertook this restructuring initiative to provide long term benefits to customers of both utilities and their shareholders.

Details of the restructuring initiative, derivation of the annual allocated shared services cost and expected savings can be found in the attached Shared Services Management Report and Agreement.

Should you have any questions, please contact the undersigned at 604-592-7784.

Yours very truly,

TERASEN GAS INC.
Per:

Original signed by:

Scott A. Thomson
Vice President, Finance and Regulatory Affairs

Attachments

Shared Services Management Report

Terasen Gas Inc. and Terasen Gas Vancouver Island

May 31, 2004

Shared Services Management Report

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.

TABLE OF CONTENTS

1.0 Executive Summary

The operational integration of Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") began in earnest September, 2003, with organizational design and plan development completed in December. Implementation of the organization and associated plans began immediately afterward and is currently ongoing. The integration exercise facilitates a shared services approach that enables both companies to harness the benefits from economies of scale by having a single management and support structure that avoids duplication of work and allows customers to benefit from the synergies created.

As a result of the restructuring initiative, TGI and TGVI are collectively expected to incur one-time restructuring charges of $15.5 million due to having 115 fewer employees. TGI and TGVI's respective share of the restructuring costs are expected to be $11.3 million and $4.2 million. Additionally, TGI and TGVI are expected to realize net savings of $8.0 million and $2.5 million for a total net savings of $10.5 million in 2004. For 2005, the anticipated net savings are expected to be approximately $9.9 million in total for the two utilities after giving effect for the additional revenue requirement resulting from capital investments at TGVI. The resulting total cumulative savings over the 2004/2005 period is expected to be $20.4 million, resulting in a net benefit over two years of $4.9 million and ongoing benefits of approximately $10 million/year, to be shared with customers according to the respective negotiated rate settlements of the two utilities. Beyond this short payback period, customers of both utilities will enjoy the benefits of lower costs as a result of the operational integration undertaken. It is also anticipated that capital investments totaling approximately $8 million are required in the 2004/2005 period to allow for a shared information technology platform, and 10% of the net book value or $2.4 million of SAP will be transferred to TGVI as part of the shared information technology strategy.

To deliver on the synergies created, both utilities moved to a shared services platform whereby the costs of management and back office support are aggregated in TGI and then allocated to TGVI. The amount of the annual shared services costs that will be subject to allocation from TGI to TGVI is estimated to be approximately $28.9 million in 2004. This results in an estimated allocation to TGVI of $2,770,000 for 2004, which is subject to true up to actual costs. This amount will be reviewed and reforecast each year and adjusted for changes in resource levels. In addition to this allocation, an estimated $290,000 of shared service costs will be charged directly to various TGVI O&M accounts from TGI and approximately $151,000 of OPEB's will be allocated directly from TGI to TGVI. This results in a total transfer of costs from TGI to TGVI of approximately $3.2 million in 2004.

2.0 Introduction

This document sets out the basis and rationale for a shared services management agreement between TGI and TGVI. Recent organizational restructuring, also referred to as integration, has resulted in the creation of a single management structure providing direction and services to both TGI and TGVI. This restructuring will enable both companies to harness the benefits from economies of scale by combining certain management and back office support activities of the two entities. A single management and support structure allows the companies to maintain an optimal level of resources, avoid duplication of work, and provide customer benefits from realized synergies.

This document includes:

(1) An overview of the integration effort;
(2) Explanation of the savings due to operational integration;
(3) A description of the shared services to be provided;
(4) The cost allocation approach used for the provision of those services; and
(5) The cost allocation methodology to be employed.

Also included, is the Shared Services Management Agreement. This agreement, which is included as Appendix A, provides transparency in separating the operating costs of the separate regulated entities and reduces administrative burden.

3.0 Overview of the Integration Initiative

The integration initiative, referred to internally as the Utilities Strategies Project ("USP"), commenced September 10th, 2003 with the planning and organizational design work completed on December 12th, 2003 followed by the execution phase which is ongoing. The USP was established to plan and implement a single management team, along with common work processes and IT platforms in order to create a more cost effective and sustainable support organization across Terasen Inc.'s natural gas utilities (TGI, TGVI, TG Squamish and TG Whistler).

The USP built on the Company's solid foundation of Operational Excellence in core activities (safety, customer satisfaction, cost, and environmental stewardship). It was broad in scope and scale, while respecting existing legal, regulatory and contractual obligations. Care was taken to be respectful and fair to employees, customers, shareholders, and the communities served and to result in sustainable, more effective, efficient gas utilities.

A number of guiding principles were employed in carrying out the project:

- The business approach and IT platforms were to be common barring compelling reasons to do otherwise.
- "Best practice" solutions were to be identified.
- Conversion costs of historical data were to be minimized while maintaining retrieval capability.
- Separate legal entities, rate bases and rate design were to be maintained.
- Cost efficiencies were expected to flow to both entities' customers according to their separate regulatory frameworks.
- Cost driver information was to be captured to ensure proper allocation of costs and savings.
- Common compensation practices for all employees were to be developed along with the goal to move to common employer status with bargaining units.
- Staffing decisions were to seek retention of the best people from both organizations.

Business process teams were established to evaluate the current business processes and to identify and recommend best practice process solutions. Representatives from Field Operations, Finance & Regulatory, Customer Care & Marketing, Human Resources, SAP Back Office Implementation, and IT & Facilities from each utility made up the business process teams. The work was carried out using a phased approach as follows:

1 – Planning

- Definition of the scope of the work.
- Project Charter development.
- Develop overall project plan.

2 – Current State Documented

- Map the TGVI and TGI "As Is" state at each functional area.

3 – Analysis

- Analyze "As Is" state.
- Identify opportunities for improvement.

4 – Design

- Design future "To Be" state.
- Identify organizational changes (inclusive of staffing requirements).

5 – Recommendation & Implementation Planning

- Develop and present recommendations to senior management regarding processes, technology and organizational structure.
- Conduct Staffing Process to retain most suitable employees from both organizations to meet daily operational requirements and future business needs.

From a governance perspective, a Policy Team was established to deal with issues related to Integration Philosophy, Human Resources Policies, Staffing Process, Early Retirement Options, briefing of senior management and other policies as required.

The planning and organizational design phase of the USP concluded in late 2003 and culminated with an internal announcement on December 12, 2003 of a new, single management team for Terasen Gas group of utilities. With the organizational blueprint in place, the companies will be in a transitional phase during 2004 as new initiatives are implemented to achieve a high degree of operational integrated by January 1, 2005. Major efforts are currently underway to ensure full integration of the management and business processes of the utilities. Many employees have assumed new roles and responsibilities as a result of the new organizational structure. Due to the organizational changes, new cost centres were needed to capture common cost pools and an allocation methodology had to be developed to ensure common costs are allocated to the respective utilities in a manner that avoids cross subsidization. Section 7.0 of this document describes the basis of the allocation methodology. Financial and statistical data resulting from the operational integration is described in the following section.

4.0 Savings due to Operational Integration

In order to complete the operational integration of the utilities, the Companies have made significant upfront investments in process changes and organizational restructuring in order to realize ongoing cost savings. TGI and TGVI will incur one-time restructuring charges totalling approximately $15.5 million. The majority of these costs were incurred in 2003 and result primarily from net staff reductions totalling 115 employees. A breakdown of the restructuring costs is summarized in Table # 1 below and the associated staff reduction levels are summarized in Table # 2.

Table # 1

Breakdown of Restructuring Costs ('000's)	**TGI**	**TGVI**	**Total**
Early Retirement and Severance Costs - 2003	$ 9,042	$ 2,231	$ 11,273
Related Restructuring Costs Incurred -2003	529		529
Sub-total	$ 9,571	$ 2,231	$ 11,802
Severance and related costs – 2004 & beyond	1,733	1,973	3,706
Total Restructuring Cost	**$ 11,304**	**$ 4,204**	**$ 15,508**

Table # 2

Summary of FTE reduction by department									
Business Unit	**Pre-Integration FTE**			**Post-Integration FTE**			**Net FTE Reduction**		
	TGI	**TGVI**	**Total**	**TGI**	**TGVI**	**Total**	**TGI**	**TGVI**	**Total**
Gas Supply & Transmission	97	14	111	96	11	107	1	3	4
Finance, Regulatory & President	51	16	67	48	-	48	3	16	19
Distribution	696	102	798	682	97	779	14	5	19
Business & IT Services	89	13	102	77	-	77	12	13	25
Operations Governance & Support	152	15	167	142	5	147	10	11	20
Marketing	77	43	120	70	36	106	7	7	14
HR	40	5	44	30	-	30	9	5	14
	1,201	**207**	**1,408**	**1,145**	**148**	**1,293**	**56**	**59**	**115**

In order to optimize the back office support functions, the integration also requires TGVI to make capital investments to harmonize Information Technology platforms and processes totalling approximately $8 million in 2004/2005. Refer to Table # 3 below for a breakdown of these costs. In addition, TGI will transfer to TGVI a 10% interest in the net book value of the SAP technology platform assets it will use to provide the services under this agreement. This will preserve the nature of the costs associated with the rate base of these assets as they are utilized. The NBV of the 10% interest is $2.4 million. The 10% figure was arrived at after consideration of the relative proportion of TGVI vs. TGI employees (11.5%) and TGVI vs. TGI customers (9.0%). A simple average of the two factors was rounded to 10%, for purposes of this calculation. These factors are described under Section 7.0 of this document.

Table # 3

Summary of Capital Investments	TGI	TGVI	Total
Order Fulfillment System		$ 1,900	$ 1,900
Back Office Business Support Integration		1,500	1,500
Meter Mgt & Mobile Systems Integration		1,800	1,800
AM/FM/Drafting Systems		700	700
Infrastructure and Operational Integration		1,400	1,400
Others		700	700
Sub-total		**$ 8,000**	**$ 8,000**
10% of SAP NBV transfer	$ (2,380)	2,380	-
Total	**$ (2,380)**	**$ 10,380**	**$ 8,000**

As part of the integration, the company is planning to convert TGVI's customer information system (Banner), which is currently outsourced to Enlogix, to the Energy system used by TGI. The customer care function of TGVI including billing and call handling will likely be contracted with Accenture Business Services when the conversion takes place. As this project is currently in the feasibility stage, the timing and projected cost of the conversion and related benefits have not been included in this report.

The operational integration initiative is expected to generate annualized O&M savings of approximately $10.8 million in 2004 and rising to more than $11 million in 2005 and thereafter. The overall net anticipated savings, due to the operational integration inclusive of depreciation, tax impacts, etc., related to the capital investment and asset transfer described earlier, is summarized in Table # 4 below:

Table # 4

	2004			2005 (1)		
	TGI	TGVI	Total	TGI	TGVI	Total
Annualized O&M Savings due to Restructuring	$ 4,356	$ 6,400	$ 10,756	$ 4,356	$ 6,700	$ 11,056
Capital Investment Related						
$8 million Capital Investment	-	(164)	(164)	-	(1,138)	(1,138)
10% of SAP transfer	418	(459)	(41)	366	(406)	(40)
Shared Services Costs Allocated & Direct (2)	3,211	(3,211)	-	3,211	(3,211)	-
Net Anticipated Savings	**$ 7,985**	**$ 2,566**	**$ 10,551**	**$ 7,933**	**$ 1,945**	**$ 9,878**

(1) Note – the 2005 costs are estimates only as these are subject to annual renewals to allow for increases or decreases in associated resource levels and associated projected system integration.

(2) Note – the Shared Services costs are described under section 7.0 of this document.

The combined net anticipated savings of $10.5 million in 2004 and $9.9 million in 2005, represents a two year total of $20.4 million. This net savings is $4.9 million greater than the restructuring charges of $15.5 million, resulting in an estimated net benefit of integration of $4.9 million over the 2004/2005 two year period.

5.0 Scope of Shared Services Covered

Although the USP had as its scope, all of the Terasen Gas group of regulated utilities, the focus to date has been primarily on TGI and TGVI, due to their scale. Furthermore, there are currently agreements in place between TGI and Terasen Gas Squamish (“TGS”) as well as between TGVI and Terasen Gas Whistler (“TGW”) regarding the allocation of costs. As a result, the following sections of this document focus on the integration of TGI and TGVI and the need for shared services between those two entities. The existing agreements with TGS and TGW will continue and are therefore out of scope for this Shared Services Management Agreement.

The operational integration of TGI and TGVI facilitates a shared services approach that enables both companies to harness the benefits from economies of scale by having a single management and support structure. Common services, described summarily below, are being provided on a shared basis by the single management structure in order to meet each company’s operating requirements. By restructuring the delivery of these services on a shared basis, the costs can be optimized across the entities to the benefit of all customers.

The common services that are delivered on a shared basis can be broken down into the following major functional areas:

- President’s Office
- Finance and Regulatory Affairs
- Human Resources
- Operations Governance and Support
- Gas Supply and Transmission
- Business and Information Technology Services
- Distribution
- Marketing

These are described in detail in Schedule “A” of the Shared Services Management Agreement.

The benefits of providing the above noted services centrally are cost efficiency and a higher standard of service. A single management and support structure allows the companies to maintain an optimal level of resources, avoid duplication of work, and customers will benefit from synergies.

The integration process, as part of the USP, commenced in some departments effective Jan 1, 2004, and work will continue throughout 2004 and beyond to integrate technology platforms and business processes. However, it should also be noted that certain integration activities pre-dated the USP. Several agreements currently exist between TGI and TGVI for the delivery of specific services. These services include Gas Control, Core Market administration, Measurement and Instrumentation. The existing agreements for the provision of these services will continue, and are therefore out of scope for the Shared Services Management Agreement.

As noted, existing contracts with TGVI will continue in effect except for Core Market Administration. Prior to the recent restructuring, TGI provided trading and risk management services to TGVI for an annual fee of $100,000. With the recent changes, Gas Supply has assumed all gas supply related activities for TGVI and now oversees the entire cost of gas amount. As a result of this change, TGI will now charge TGVI an amount of $356,900 per annum or $29,742 per month for services relating to Core Market Administration.

6.0 Cost Allocation Approach used for Shared Services Costs

As described in previous sections of this document, the USP led to the establishment of a single management team and organization for both entities. One of the requirements resulting from the operational integration of the two companies was to establish a fair and reasonable cost allocation approach to share costs between the two regulated entities. In arriving at the cost allocation approach used, the Company drew from the report prepared by Deloitte & Touche that presents a framework based on generally accepted methods of allocating shared services costs to affiliates (filed as part of the Terasen Corporate Separation Study, Section B, Tab 9 of the 2003 Annual Review). This report was commissioned by Terasen Inc. (TI) and used in establishing the cost allocation basis for management services provided by TI to TGI commencing January 1, 2004. The framework used as the basis for the allocation of Shared Service costs is consistent with the approach used by Terasen Inc. The British Columbia Utilities Commission ("the Commission") approved the cost allocation fee to TGI in its Decision dated December 17, 2003 via Commission Order No. G-80-03.

In addition, the Company created guiding objectives for the development of cost allocation approach. These guiding objectives were to ensure:

- The avoidance of cross subsidization between regulated entities.
- The establishment of procedures that are efficient to administer and account for.
- The creation of a methodology that is reasonable, flexible and responsive to organizational changes.
- The demonstration of a causal link between the allocation of cost and the cause of the costs incurred through the use of cost drivers.

7.0 Cost Allocation Methodology

The operating expenses of each utility are comprised of direct expenses and shared services expenses. The shared service expenses relate to tasks performed centrally and the majority of costs to provide these types of services are fixed in nature. Once office facilities, staff and associated processes and systems have been established, the incremental cost to provide additional services is marginal. Providing the service centrally maximizes the utilization of the fixed costs resulting in cost efficiency. To deliver on the synergies created by this centralization, the Company moved to a shared services platform whereby the costs of management and back office support are aggregated in TGI and then allocated to TGVI.

A review of all departmental activities in the company was conducted of the common services and/or management responsibilities for operations or activities of the two entities. A determination was made of the most appropriate basis to recover costs relating to the services provided to TGVI, either through a cost allocation calculation or through a direct assignment basis utilizing timesheets.

The common services were described in summary fashion, under Section 5 above and are listed in detail in Schedule "A" of the Shared Services Management Agreement. Many of these services relate to policy, strategy and governance activities in addition to high value skills delivery in specialized areas. A significant portion of these expenses, such as human resources and regulatory support, for example, are most appropriately recovered via an allocation process. However, some of these services such as engineering services can more effectively be charged directly based on timesheet information.

All of the shared services costs were reviewed with respect to the utilization of the most appropriate allocation method and the allocation of the shared service costs to TGVI can be broken down into the following two categories, which are summarized below:

- Direct Charges - costs such as TGVI field operations costs and Commission assessment fees that can be clearly attributed to TGVI will be charged *directly* to TGVI. Support department staff including engineering, drafting, and information technology services and enterprise resource planning employed by TGI will provide services to TGVI and will charge their costs to TGVI via timesheets, consistent with the Transfer Pricing policy.

- Allocations - costs incurred in departments such as HR, Finance and Information Technology that are not involved with the direct delivery of services to end customers will be captured in departmental cost pools and then *allocated* to TGVI based on the allocation factors included in Table # 5 below:

Table # 5

	Expressed as Numbers			Allocation Factors Expressed as %s		
COST DRIVERS	**TGI**	**TGVI**	**Total**	**TGI**	**TGVI**	**Total**
Number of Customer	775,516	76,842	852,358	91.0%	9.0%	100.0%
Number of Employees (FTE/s)	1,142.2	148	1,290.2	88.5%	11.5%	100%

Based on the allocation factors described above, table # 6 below sets out the shared service costs to be *allocated* to TGVI for 2004:

Table # 6

Shared Service Costs To be allocated	Cost Driver*	Total ($000)	Allocation Factors*	Allocated ($000)
President	# of Customers	$ 1,235	9%	$ 111
Finance & Regulatory	# of Customers	5,313	9%	479
Human Resources	# of Employees	3,119	11.5%	358
Operations Governance & Support	# of Customers/# of Employees	5,732	9.7% *	557
Gas Supply & Transmission	# of Customers	2,186	9%	197
Business & IT Services	# of Customers/# of Employees	2,940	10.8% *	317
Distribution	# of Customers	4,132	9%	372
Marketing	# of Customers	4,199	9%	379
TOTAL		**$ 28,856**		**$ 2,770**

Where more than one cost driver is used, the cost pool for allocation is segregated by cost driver. The weighted average for the organizational unit is reflected in the table above.

The amount of the annual shared services cost allocation from TGI to TGVI, is estimated at $2,770,000 for 2004. This amount will be subject to a true up at year end when actual shared costs are known. The shared services allocation charges will be in accordance with the shared services agreed to in the contract. Any services not previously contemplated will be provided in a separate supplement to the agreement. The cost allocation will be updated prior to the start of each year and adjusted for changes in anticipated resource levels accordingly.

Shared service costs to be recovered by TGI from TGVI by direct charge for 2004 are estimated at $290,000. Additionally, OPEB's, which are directly attributable to TGVI staff will be allocated directly to TGVI from TGI. The allocation of OPEB's to TGVI is estimated at $151,000. The total shared service costs that will be allocated and charged directly from TGI to TGVI is estimated at $3,211,000, as set out in table # 7 below.

Table # 7

	2004 Total
Allocation of Shared Services Costs	2,770
Direct OPEB Costs	151
Direct Timesheet based Charges to O&M	290
Total Shared Services Costs – Direct and Allocated	**$ 3,211**

Appendix A

Shared Services Management Agreement

THIS AGREEMENT made as of and effective January 1, 2004

BETWEEN:

TERASEN GAS (VANCOUVER ISLAND) INC.
1675 Douglas Street,
PO Box 3777
Victoria, British Columbia
V8W 3V3

(**"TGVI"**)

AND:

TERASEN GAS INC.
16705 Fraser Highway,
Surrey, British Columbia
V3S 2X7

(**"TGI"**)

WHERAS

A. TGVI is the owner and operator of the natural gas transmission and distribution facilities in British Columbia serving the communities of Vancouver Island and the Sunshine Coast (the "Facilities"); and

B. TGVI wishes to retain TGI to provide certain administrative and management services to it in respect to the ownership and common management of the operation of operations of its transmission pipeline and distribution business on the terms and conditions set out herein.

WITNESSES that, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) "**Force Majeure**" has the meaning assigned to such term in Section 9.1;

(c) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) "**Services**" means the administrative and management services to be provided to TGVI by TGI as more particularly described in Section 2.1.

1.2 Schedules

The following are the schedules attached to, and are incorporated by reference into, this Agreement:

Schedule "A"	Description of Services
Schedule "B"	Pricing

1.3 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

2) any reference in this Agreement to a designated "Article", "Section" or other subdivision is to the designated Article, Section or other subdivision of this Agreement,

3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision,

4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,

5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and

6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2

SERVICES

2.1 Services

TGI hereby agrees to provide to TGVI those administrative and management services described in Schedule A.

2.2 No Obligation to Provide Additional Services

TGI shall not perform, and TGI shall have no obligation to perform, any services on behalf of TGVI in respect of the Facilities other than as set out in this Agreement or any similar agreement.

2.3 Consultation with TGVI

TGI will consult with TGVI as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between TGI and TGVI. In performing the Services, TGI shall be an independent contractor. TGI employees shall not be considered employees of TGVI for any purpose.

2.5 Compliance

In performing the Services, TGI will comply with all Applicable Laws.

PART 3

COMPENSATION

3.1 Compensation for Services

TGVI agrees to pay to TGI for the administration and management services the compensation set out in Schedule B.

3.2 Amendment to Costs

The amounts set out in Schedule “B” may be amended from time to time by agreement between the parties to reflect any material change in the cost of providing the services or in the business operations of TGVI.

3.3 Invoicing

TGI will invoice TGVI in respect of the Services no later than the 25^{th} day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

(a) Except with respect to those portions of an Invoice which are the subject of a bona fide dispute between the parties, invoices shall be payable within thirty (30) days from the date of the invoice.

(b) Any amount to be remitted by TGVI to TGI and not remitted on or before the date on which it is due shall thereafter bear interest at an annual rate equal to the prime rate of interest of the Toronto-Dominion Bank (or its successor or permitted assign) (Toronto, Main Branch) plus one percent (1%) calculated daily from the date the amounts become due.

(c) Effective December 31, 2004 TGI will prepare financial accounting of the actual costs and the allocated costs, and will make adjustments based on additional amount to be paid by TGVI or return an overpayment.

(d) Payments due and owing as a result of the accounting will be paid no later then the end of the first quarter of the following year.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by TGVI

Subject to Section 4.4, TGVI will indemnify, defend and hold harmless TGI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with TGI’s provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of TGI.

4.2 Limitation of Liability of TGI

Neither TGI nor any of its directors, officers, employees, agents or contractors will be liable to TGVI for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which TGVI may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with TGI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of TGI.

4.3 Indemnity by TGI

Subject to Section 4.4. TGI will indemnify, defend and hold harmless TGVI from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which TGVI may suffer or incur as a result of any act or omission or error of judgement as a result of which TGI is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF TGVI

5.1 Covenants by TGVI

TGVI covenants and agrees to:

(a) fully co-operate with TGI in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by TGVI to TGI or any other Person pursuant to or as contemplated by this Agreement.

PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of TGI

TGI hereby represents and warrants to TGVI as representations and warranties which are true as at the date hereof and which will be true during the term of TGI's appointment hereunder:

(a) TGI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGI has full power and authority to perform its obligations hereunder,

(b) this Agreement constitutes a valid and binding obligation of TGI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) TGI possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of TGVI

TGVI hereby represents and warrants to TGI as representations and warranties which are true as at the date hereof and which will be true during the term of TGI's appointment hereunder:

(a) TGVI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGVI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of TGVI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective retroactively from January 1, 2004 and will continue until December 31, 2004. Thereafter the Agreement will automatically be renewed for further one year terms subject to Sections 7.2 and 7.3 below.

7.2 Termination

TGI's appointment hereunder may be terminated at any time:

(a) by TGI giving TGVI written notice of such termination:

(i) if TGVI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGVI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGVI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGVI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGVI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event TGVI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGVI of written notice thereof from TGI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGI that TGVI is in breach is conceded to be correct by TGVI or found to be correct by an arbitrator pursuant to Section 8.1;

(b) by TGVI giving TGI written notice of such termination:

(i) if TGI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event TGI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGI of written notice thereof from TGVI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGVI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGVI that TGI is in breach is conceded to be correct by TGI or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Termination Without Cause

Notwithstanding Section 7.2 above either party may, upon obtaining the other party’s written consent, terminate this Agreement without penalty or damages upon giving thirty (30) days written notice.

7.4 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, TGI will have no further obligations under Article 2 and will promptly deliver to TGVI any material documents in the possession of TGI pertaining to the business of TGVI.

7.5 Compensation of TGI on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, TGVI will pay to TGI all amounts owing to TGI hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this Section, the fees provided for in Article 3 which are payable to TGI on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8

ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between TGI and TGVI regarding any allegation that TGVI or TGI is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the Rules of Procedure for Commercial Mediation of The Canadian Foundation for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9

FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, “Force Majeure” shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

MISCELLANEOUS

10.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

10.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

10.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

10.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement the 31st day of May, 2004.

TERASEN GAS (VANCOUVER ISLAND) INC.

By: *Original signed by Randy Jespersen*

Title: *President*

TERASEN GAS INC.

By: *Original signed by Scott Thomson*

Title: *Vice President of Finance and Regulatory Affairs*

Schedule "A"

Description of Services

Schedule A
Services

On a shared basis, the personnel from the following departmental units of TGI will provide services

(1) **President's Office.** The role and function of the President of TGI is to provide:

(a) governance and liaisons to direct development and implementation of strategic, operational and capital plans;

(b) governance assurance that controls are in place to ensure the Company's are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(c) alignment and communication of the vision and direction to employees and other stakeholders;

(d) executive level succession planning and development to prepare and maintain exceptional leadership; and

(e) act as the principal spokesperson in maintaining close communication with government and the public.

(2) **Finance and Regulatory Affairs**. The role and function of the Finance and Regulatory Affairs department is to provide the following services:

(a) policy direction and oversight of services related to key financial areas including Strategic Planning, Regulatory Affairs, management and financial reporting, and the capital management office;

(b) oversee the understanding, communication and adherence to accounting policies procedures and practices;

(c) lead financial elements of regulatory processes;

(d) establish and execute the process for managing and facilitating the prioritization of all capital expenditures in the TGI companies through the Capital Management Office;

(e) provide high-level, strategic regulatory advice & expertise necessary to ensure the regulatory agenda/platform supports the current and future business needs of the companies;

(f) maintain/enhance the ongoing relationship that is required between TGI/TGVI (via the Regulatory Services department) and key stakeholders in the regulatory environment;

(g) regulatory support from the initial planning stage, including leading consultations with the BCUC and stakeholders and the submission of applications to the BCUC, through to the final implementation and reporting;

(h) development and maintenance of rate structures and the tariff/tariff supplements, and the analysis of cost allocation methodologies, allocated cost of service studies, for gas costs and distribution margin to support rate design applications;

(i) development of strategic and tactical aspects of regulatory platform and creation of applications for revenue requirement, PBR, ROE mechanism, SQI development. Studies and/or Applications may be directed by the BCUC or may be based on corporate strategic requirements;

(j) interpretation, education and communication of new and existing regulatory policies throughout the company, including the development and communication of a corporate regulatory policy;

(k) gathering and analysis of comparative data/competitive intelligence to assess trends within the energy industry & TGI/TGVI position relative to other utilities, particularly those within Canada and the Pacific Northwest;

(l) development of TGI/TGVI financial accounting policies and procedures;

(m) reviewing and maintaining the code of general ledger accounts;

(n) accounting for and validation of all financial statement elements including revenues, cost of gas, deferral accounts, financing costs, bank accounts, the accounting for continuing services and the billing of inter-company transactions;

(o) monthly reporting, variance analysis and year-end forecasting;

(p) external audit coordination and the preparation of non-consolidated financial statements;

(q) annual and multi-year budget processes;

(r) performance measurement and cost analysis; and

(s) asset and Plant accounting.

(3) **Human Resources**. This department is focused on providing HR services to support human resource and related business needs of the operations of the Terasen group of companies. The functional areas and the services they provide are:

(a) advice and guidance to employees and line managers on human resources management activities such as performance management, disability management, succession planning and organizational development;

(b) labour relations advice and guidance including negotiating collective agreements, contract administration and application, grievance and arbitration handling and union relations;

(c) processing activities related to costing time, pay, benefits and pension;

(d) records management and reporting; and

(e) recruitment and staffing.

(4) **Operations Governance and Support**. The role and function of the Operations Governance Support Management team is to provide the following services:

(a) policy direction and oversight of services related to key operational areas including governance of Engineering, Occupational Health & Safety, and the Environment, in addition to Emergency Planning and Public Safety;

(b) management and oversight of services related to project planning and design, system integrity, corrosion control, property services, facility records and geographical information system mapping;

(c) implementation of maintenance of management systems that control and support emergency planning, security and public safety activities to ensure compliance with applicable laws, company policy and industry codes of practice;

(d) ensuring emergency response plans are maintained, updated and tested on a regular basis;

(e) working with governmental and non-governmental agencies to develop and coordinate emergency response protocols;

(f) coordinating the development of security standards and programs to protect TGI facilities and assets;

(g) coordinating and implementing a public safety awareness program and standards to ensure an appropriate level of public safety communication and program delivery to meet “duty of care” and “duty to warn” due diligence;

(h) delivering trades training services to key operations groups within the utility to maintain skill competencies and ensure compliance with laws, policies and industry codes;

(i) maintenance of employee training records;

(j) corporate governance of management systems controlling environmental affairs, employee occupational health & safety, and the design, construction and operation of the gas pipeline system;

(k) monitoring and reporting of compliance with all applicable laws, company policies and industry codes of practice;

(l) advice and direction to Operations groups in support of their accountability to manage specific Environment, Health & Safety risks;

(m) managing a common standards framework to ensure environmental compliance, a safe working environment for employees and consistent, efficient application of standards;

(n) ensure that the workforce meets Workers Compensation Board legislative requirements;

(o) uphold customer and public expectations regarding environmental due diligence and habitat preservation;

(p) responsible for project management and professional services to meet the requirements of managers;

(q) responsible for developing and maintaining a comprehensive Integrity Management Plan for the gas distribution and transmission operating plant assets. Also provides risk-based integrity management services related to operating plant and surrounding natural hazards, principally focused on material defect, corrosion, geotechnical and hydro-technical risks;

(r) responsible for Operation and Maintenance of systems providing cathodic protection to operating plant;

(s) responsible for the planning of lowest cost system improvements for the gas Distribution and Transmission systems, as well as hydraulic scenario analyses for operational enquiries and project development;

(t) responsible for managing all land rights and land tenure issues including property taxation, acquisition & disposal, leases, right of way agreements, environmental reviews and first nations negotiations;

(u) responsible for maintenance and security of all pipeline rights of way; this includes third party crossing permits & inspections, sub-division approvals, vegetation management, right of way patrol, public awareness and encroachment removal;

(v) responsible for completing new mains and service construction drawings and as-built mapping, as well as detailed design drawings for engineering projects as required by the Distribution and Transmission asset managers;

(w) responsible for final data integrity checking of field drawings prior to data entry in the Geographic Information System;

(x) responsible for developing and maintaining the Geographic Information Systems (GIS), and maintaining all records for Distribution and Transmission facilities; and

(y) Responsible for providing Location Records information for underground facilities, as requested through BC One Call.

(5) **Gas Supply and Transmission ("GS&T")**. GS&T provides policy direction and oversight services in addition to business performance management related to key operational areas. The GST department is responsible for:

(a) gas supply which secures the commodity (gas or propane) and ensures it gets to TGI's Transmission network;

(b) transmission which moves the gas to TGI's Distribution network and also manages LNG storage;

(c) business development which ensures that, at a regional level, appropriate capacity and capabilities are available to serve current and future consumers of natural gas;

(d) ensuring there are reliable and secure peaking supplies of natural gas for all core customers at an optimum cost;

(e) arranging natural gas supply to firm and interruptible customers on the distribution system;

(f) providing intra-day balancing supply to stabilize the pressures on the TGI distribution system;

(g) facilitating all gas scheduling and nominations on TGI and third party transmission systems and on the TGI distribution system;

(h) optimizing the value of the natural gas supply portfolio for the benefit of customers on the TGI system;

(i) managing relationships with upstream pipeline companies (Duke, TCPL) to the benefit of TGI's customers;

(j) developing natural gas and propane portfolios for TG and TGVI (Annual Contract Plans);

(k) evaluating supply and asset options (Send out Model);

(l) price risk management for TGI and TGVI;

(m) portfolio and price risk analysis for Gas Supply and Business Development;

(n) provision of Market Information;

(o) execution of the Annual Contract Plans (Resource Stack) to meet core demand in a cost effective manner;

(p) execution of financial hedging transactions;

(q) managing issues upstream/downstream of TGI/TGVI facilities and building relationships with PNW participants;

(r) managing relationships/service delivery with EMS/Transmission customers;

(s) compliance functions;

(t) regional resource planning and other forecasting needs;

(u) maintaining regulatory relationships regarding ongoing Transmission asset management, and managing Transmission safety and pipeline integrity programs;

(v) developing and championing the regional natural gas infrastructure strategy;

(w) identifying, evaluating and developing appropriate growth opportunities; and

(x) managing major third-party transmission shipper relationships.

(6) **Business and Information Technology Services**. This Division provides business services, information technology application and infrastructure management services which enable the operating areas of the company to provide the delivery of utility services. The Division's focus is company-wide and broad in scope.

(a) Policy direction and oversight of services related to key support areas including Business services which is comprised of Facilities services, Purchasing and accounts payable.

(b) Management and oversight of services related to information technology application and infrastructure management services.

(c) Procurement for materials and services.

(7) Accounts Payable.

(a) The accounts payable group is responsible for ensuring vendors are paid accurately and in a timely manner.

(b) Provides administrative support for corporate credit card program.

(c) Facilities Management Services has responsibility for all TGI buildings throughout the service territory. It provides building equipment maintenance, security services and cleaning services. It also arranges and negotiates new space requirements and telecom requests for the organization.

(8) IT Services.

(a) Application Management Services manages the overall data and application architecture for TGI and provides application integration design and delivery services. It is a joint custodian of the TGI Technology Architecture Standards.

(b) Provides application architecture and technology consulting services and ensures application projects are developed according to TGI technology standards.

(c) IT Infrastructure Management plans, forecasts, and designs for future infrastructure capacity requirements and develops and directs the implementation of new technology services at TGI. It is a joint custodian of the TGI Technology Architecture Standards.

(d) IT Infrastructure Management ensures the availability, integrity and security of TGI critical enterprise infrastructure, including: Wide Area Network (WAN), distributed applications/systems, desktop and mobile computer devices, and outsource management.

(9) **Distribution.** The role and function of the Distribution business unit is to provide the following services:

(a) policy direction and oversight of services related to key operational areas including Distribution operations and maintenance, Emergency Management Services, Account Services and Fieldwork, Distribution Operations Support, Measurement Technologies, and Shops, Inventory and Trucking;

(b) general management and oversight of services are focused on delivering a safe, reliable and cost-effective gas distribution system for residential, commercial and industrial customers;

(c) regional managers and front line field Operations and Install managers who are responsible for day-to-day operations in specific geographic areas;

(d) responsible for ensuring that materials and services are manufactured, tested for fitness of use, and distributed to TGI operating and support groups;

(e) measurement technologies is responsible for maintaining the accuracy of metering devices as well as providing energy consumption data to large commercial and industrial customers; and

(f) provide fabrication of critical system components that are installed in the distribution system.

(10) **Marketing**. The primary responsibilities of Marketing are to manage relations with all customer groups and stakeholders; to produce energy use and account growth forecasts; and to manage TGI's internal and external communications requirements. Marketing provides an organizational focus in the management of these responsibilities and in the delivery of marketing services.

Marketing services provided through TGI to TGVI on a shared service basis fall into the following service areas:

(a) responsibility for providing overall policy direction and oversight of services relating to the marketing function, including overseeing the development and implementation of marketing initiatives and programs;

(b) provide overall policy direction and oversight of services relating to residential and small commercial markets;

(c) provides overall policy direction and oversight of services relating to large commercial and industrial markets;

(d) planning and delivery of customer education and communication, product development, and market research;

(e) program development, carries out trade relations activities, manages customer connection policies, and produces marketing communications;

(f) deals with escalated calls from the call centres;

(g) creates messaging for customer education and communication on the topics of rate changes, natural gas prices, competition with alternative fuels, billing issues, customer connection policies and regulatory changes (e.g., gas cost increase, rate design changes);

(h) provides market research activities focus on customer research (e.g., end-use studies), customer satisfaction, safety, and attitudes and opinions around Company initiatives;

(i) oversees both the Main Extension test, and the Company's service line policies;

(j) evaluates existing offerings to determine if they represent the right mix of customer service and core market cost recovery and the design, negotiation and submission of new an amended services to the British Columbia Utilities Commission;

(k) develops customer energy use and customer additions forecasts;

(l) provides analysis and decision support on longer-term supply/demand and pricing issues, and performs portfolio modeling;

(m) provides overall policy direction and oversight of services relating to TGVI's community and aboriginal relations requirements; and

(n) provides internal and external communications services for the Company, including employee communication and media relations.

Schedule “B”

Pricing

Schedule B
Estimated Pricing

Shared Services Costs to be Allocated	Cost Driver	Annual Total ($000)	Allocation Factors	Allocated ($000)
President	# of Customers	$1,235	9%	$111
Finance & Regulatory	# of Customers	5,313	9%	479
Human Resources	# of Customers	3,119	11.5%	358
Operations Governance & Support	# of Customers/ # of Employees	5,732	9.7%	557
Gas Supply & Transmission	# of Customers	2,186	9%	197
Business & IT Services	# of Customers/ # of Employees	2,940	10.8%	317
Distribution	# of Customers	4,132	9%	372
Marketing	# of Customers	4,132	9%	379
TOTAL		**$28,856**		**$2,770**
Annual Monthly Allocated				**$230.833**

Note the annual allocated amounts shown in this chart are proforma estimates that are subject to year end true-up.

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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Surrey, B.C. V3S 2X7
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www.terasengas.com

May 31, 2004

British Columbia Utilities Commission
Box 250
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Mr. R.J. Pellatt

Dear Sir:

Re: Terasen Gas Inc. and Terasen Gas Vancouver Island
Shared Services Management Agreement

During the regulatory rate setting process for test years 2003 and 2004, Terasen Gas Inc. indicated that the acquisition of Centra BC (TGVI) and Centra Whistler would provide an opportunity to create synergies. A number of synergies were identified and reflected in 2003 revenue requirements and by formula into the 2004 rates of Terasen Gas Inc. (TGI). Similarly, savings accruing to TGVI were included in its revenue requirement filing in the fall of 2003.

TGI and TGVI have now undertaken a major restructuring initiative which will deliver substantial savings for the two companies. A single management team is now in place and common work processes and information technology platforms are being developed and implemented to create a more cost effective and sustainable support organization. The operational integration of TGI and TGVI require significant upfront investments in process changes and organizational restructuring. Capital investments totalling some $8 million are expected to be incurred to harmonize the information technology platforms including the transfer of a 10% interest ($2.4 million) in the net book value of the SAP platform of TGI. In total, $15.5 million have or will be incurred on restructuring, resulting in a net staff reduction of 115 employees. These upfront investment costs are expected to generate sustainable annual savings exceeding $10 million per year between the two companies.

With a single management and support team, services will be delivered on a shared basis. Utilizing a framework similar to that used by Terasen Inc. to allocate corporate centre management fees to TGI, an allocated shared services cost for the provision of shared services to TGVI is estimated to be $2.8 million for 2004. This annual allocated shared services cost will be trued up at year end when actual shared costs are known. TGVI and its customers are expected to realize net annualized benefits of approximately $2.0 million once all costs including shared service cost allocations are factored in. Terasen undertook this restructuring initiative to provide long term benefits to customers of both utilities and their shareholders.

Details of the restructuring initiative, derivation of the annual allocated shared services cost and expected savings can be found in the attached Shared Services Management Report and Agreement.

Should you have any questions, please contact the undersigned at 604-592-7784.

Yours very truly,

TERASEN GAS INC.
Per:

Original signed by:

Scott A. Thomson
Vice President, Finance and Regulatory Affairs

Attachments

Shared Services Management Report

Terasen Gas Inc. and Terasen Gas Vancouver Island

May 31, 2004

Shared Services Management Report

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.

TABLE OF CONTENTS

1.0 Executive Summary

The operational integration of Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") began in earnest September, 2003, with organizational design and plan development completed in December. Implementation of the organization and associated plans began immediately afterward and is currently ongoing. The integration exercise facilitates a shared services approach that enables both companies to harness the benefits from economies of scale by having a single management and support structure that avoids duplication of work and allows customers to benefit from the synergies created.

As a result of the restructuring initiative, TGI and TGVI are collectively expected to incur one-time restructuring charges of $15.5 million due to having 115 fewer employees. TGI and TGVI's respective share of the restructuring costs are expected to be $11.3 million and $4.2 million. Additionally, TGI and TGVI are expected to realize net savings of $8.0 million and $2.5 million for a total net savings of $10.5 million in 2004. For 2005, the anticipated net savings are expected to be approximately $9.9 million in total for the two utilities after giving effect for the additional revenue requirement resulting from capital investments at TGVI. The resulting total cumulative savings over the 2004/2005 period is expected to be $20.4 million, resulting in a net benefit over two years of $4.9 million and ongoing benefits of approximately $10 million/year, to be shared with customers according to the respective negotiated rate settlements of the two utilities. Beyond this short payback period, customers of both utilities will enjoy the benefits of lower costs as a result of the operational integration undertaken. It is also anticipated that capital investments totaling approximately $8 million are required in the 2004/2005 period to allow for a shared information technology platform, and 10% of the net book value or $2.4 million of SAP will be transferred to TGVI as part of the shared information technology strategy.

To deliver on the synergies created, both utilities moved to a shared services platform whereby the costs of management and back office support are aggregated in TGI and then allocated to TGVI. The amount of the annual shared services costs that will be subject to allocation from TGI to TGVI is estimated to be approximately $28.9 million in 2004. This results in an estimated allocation to TGVI of $2,770,000 for 2004, which is subject to true up to actual costs. This amount will be reviewed and reforecast each year and adjusted for changes in resource levels. In addition to this allocation, an estimated $290,000 of shared service costs will be charged directly to various TGVI O&M accounts from TGI and approximately $151,000 of OPEB's will be allocated directly from TGI to TGVI. This results in a total transfer of costs from TGI to TGVI of approximately $3.2 million in 2004.

2.0 Introduction

This document sets out the basis and rationale for a shared services management agreement between TGI and TGVI. Recent organizational restructuring, also referred to as integration, has resulted in the creation of a single management structure providing direction and services to both TGI and TGVI. This restructuring will enable both companies to harness the benefits from economies of scale by combining certain management and back office support activities of the two entities. A single management and support structure allows the companies to maintain an optimal level of resources, avoid duplication of work, and provide customer benefits from realized synergies.

This document includes:

(1) An overview of the integration effort;
(2) Explanation of the savings due to operational integration;
(3) A description of the shared services to be provided;
(4) The cost allocation approach used for the provision of those services; and
(5) The cost allocation methodology to be employed.

Also included, is the Shared Services Management Agreement. This agreement, which is included as Appendix A, provides transparency in separating the operating costs of the separate regulated entities and reduces administrative burden.

3.0 Overview of the Integration Initiative

The integration initiative, referred to internally as the Utilities Strategies Project ("USP"), commenced September 10th, 2003 with the planning and organizational design work completed on December 12th, 2003 followed by the execution phase which is ongoing. The USP was established to plan and implement a single management team, along with common work processes and IT platforms in order to create a more cost effective and sustainable support organization across Terasen Inc.'s natural gas utilities (TGI, TGVI, TG Squamish and TG Whistler).

The USP built on the Company's solid foundation of Operational Excellence in core activities (safety, customer satisfaction, cost, and environmental stewardship). It was broad in scope and scale, while respecting existing legal, regulatory and contractual obligations. Care was taken to be respectful and fair to employees, customers, shareholders, and the communities served and to result in sustainable, more effective, efficient gas utilities.

A number of guiding principles were employed in carrying out the project:

- The business approach and IT platforms were to be common barring compelling reasons to do otherwise.
- "Best practice" solutions were to be identified.
- Conversion costs of historical data were to be minimized while maintaining retrieval capability.
- Separate legal entities, rate bases and rate design were to be maintained.
- Cost efficiencies were expected to flow to both entities' customers according to their separate regulatory frameworks.
- Cost driver information was to be captured to ensure proper allocation of costs and savings.
- Common compensation practices for all employees were to be developed along with the goal to move to common employer status with bargaining units.
- Staffing decisions were to seek retention of the best people from both organizations.

Business process teams were established to evaluate the current business processes and to identify and recommend best practice process solutions. Representatives from Field Operations, Finance & Regulatory, Customer Care & Marketing, Human Resources, SAP Back Office Implementation, and IT & Facilities from each utility made up the business process teams. The work was carried out using a phased approach as follows:

1 – Planning

- Definition of the scope of the work.
- Project Charter development.
- Develop overall project plan.

2 – Current State Documented

- Map the TGVI and TGI "As Is" state at each functional area.

3 – Analysis

- Analyze "As Is" state.
- Identify opportunities for improvement.

4 – Design

- Design future "To Be" state.
- Identify organizational changes (inclusive of staffing requirements).

5 – Recommendation & Implementation Planning

- Develop and present recommendations to senior management regarding processes, technology and organizational structure.
- Conduct Staffing Process to retain most suitable employees from both organizations to meet daily operational requirements and future business needs.

From a governance perspective, a Policy Team was established to deal with issues related to Integration Philosophy, Human Resources Policies, Staffing Process, Early Retirement Options, briefing of senior management and other policies as required.

The planning and organizational design phase of the USP concluded in late 2003 and culminated with an internal announcement on December 12, 2003 of a new, single management team for Terasen Gas group of utilities. With the organizational blueprint in place, the companies will be in a transitional phase during 2004 as new initiatives are implemented to achieve a high degree of operational integrated by January 1, 2005. Major efforts are currently underway to ensure full integration of the management and business processes of the utilities. Many employees have assumed new roles and responsibilities as a result of the new organizational structure. Due to the organizational changes, new cost centres were needed to capture common cost pools and an allocation methodology had to be developed to ensure common costs are allocated to the respective utilities in a manner that avoids cross subsidization. Section 7.0 of this document describes the basis of the allocation methodology. Financial and statistical data resulting from the operational integration is described in the following section.

4.0 Savings due to Operational Integration

In order to complete the operational integration of the utilities, the Companies have made significant upfront investments in process changes and organizational restructuring in order to realize ongoing cost savings. TGI and TGVI will incur one-time restructuring charges totalling approximately $15.5 million. The majority of these costs were incurred in 2003 and result primarily from net staff reductions totalling 115 employees. A breakdown of the restructuring costs is summarized in Table # 1 below and the associated staff reduction levels are summarized in Table # 2.

Table # 1

Breakdown of Restructuring Costs ('000's)	TGI	TGVI	Total
Early Retirement and Severance Costs - 2003	$ 9,042	$ 2,231	$ 11,273
Related Restructuring Costs Incurred -2003	529		529
Sub-total	$ 9,571	$ 2,231	$ 11,802
Severance and related costs – 2004 & beyond	1,733	1,973	3,706
Total Restructuring Cost	**$ 11,304**	**$ 4,204**	**$ 15,508**

Table # 2

Summary of FTE reduction by department									
Business Unit	Pre-Integration FTE			Post-Integration FTE			Net FTE Reduction		
	TGI	TGVI	Total	TGI	TGVI	Total	TGI	TGVI	Total
Gas Supply & Transmission	97	14	111	96	11	107	1	3	4
Finance, Regulatory & President	51	16	67	48	-	48	3	16	19
Distribution	696	102	798	682	97	779	14	5	19
Business & IT Services	89	13	102	77	-	77	12	13	25
Operations Governance & Support	152	15	167	142	5	147	10	11	20
Marketing	77	43	120	70	36	106	7	7	14
HR	40	5	44	30	-	30	9	5	14
	1,201	**207**	**1,408**	**1,145**	**148**	**1,293**	**56**	**59**	**115**

In order to optimize the back office support functions, the integration also requires TGVI to make capital investments to harmonize Information Technology platforms and processes totalling approximately $8 million in 2004/2005. Refer to Table # 3 below for a breakdown of these costs. In addition, TGI will transfer to TGVI a 10% interest in the net book value of the SAP technology platform assets it will use to provide the services under this agreement. This will preserve the nature of the costs associated with the rate base of these assets as they are utilized. The NBV of the 10% interest is $2.4 million. The 10% figure was arrived at after consideration of the relative proportion of TGVI vs. TGI employees (11.5%) and TGVI vs. TGI customers (9.0%). A simple average of the two factors was rounded to 10%, for purposes of this calculation. These factors are described under Section 7.0 of this document.

Table # 3

Summary of Capital Investments	TGI	TGVI	Total
Order Fulfillment System		$ 1,900	$ 1,900
Back Office Business Support Integration		1,500	1,500
Meter Mgt & Mobile Systems Integration		1,800	1,800
AM/FM/Drafting Systems		700	700
Infrastructure and Operational Integration		1,400	1,400
Others		700	700
Sub-total		**$ 8,000**	**$ 8,000**
10% of SAP NBV transfer	$ (2,380)	2,380	-
Total	**$ (2,380)**	**$ 10,380**	**$ 8,000**

As part of the integration, the company is planning to convert TGVI's customer information system (Banner), which is currently outsourced to Enlogix, to the Energy system used by TGI. The customer care function of TGVI including billing and call handling will likely be contracted with Accenture Business Services when the conversion takes place. As this project is currently in the feasibility stage, the timing and projected cost of the conversion and related benefits have not been included in this report.

The operational integration initiative is expected to generate annualized O&M savings of approximately $10.8 million in 2004 and rising to more than $11 million in 2005 and thereafter. The overall net anticipated savings, due to the operational integration inclusive of depreciation, tax impacts, etc., related to the capital investment and asset transfer described earlier, is summarized in Table # 4 below:

Table # 4

	2004			2005 (1)		
	TGI	TGVI	Total	TGI	TGVI	Total
Annualized O&M Savings due to Restructuring	$ 4,356	$ 6,400	$ 10,756	$ 4,356	$ 6,700	$ 11,056
Capital Investment Related						
$8 million Capital Investment	-	(164)	(164)	-	(1,138)	(1,138)
10% of SAP transfer	418	(459)	(41)	366	(406)	(40)
Shared Services Costs Allocated & Direct (2)	3,211	(3,211)	-	3,211	(3,211)	-
Net Anticipated Savings	**$ 7,985**	**$ 2,566**	**$ 10,551**	**$ 7,933**	**$ 1,945**	**$ 9,878**

(1) Note – the 2005 costs are estimates only as these are subject to annual renewals to allow for increases or decreases in associated resource levels and associated projected system integration.

(2) Note – the Shared Services costs are described under section 7.0 of this document.

The combined net anticipated savings of $10.5 million in 2004 and $9.9 million in 2005, represents a two year total of $20.4 million. This net savings is $4.9 million greater than the restructuring charges of $15.5 million, resulting in an estimated net benefit of integration of $4.9 million over the 2004/2005 two year period.

5.0 Scope of Shared Services Covered

Although the USP had as its scope, all of the Terasen Gas group of regulated utilities, the focus to date has been primarily on TGI and TGVI, due to their scale. Furthermore, there are currently agreements in place between TGI and Terasen Gas Squamish ("TGS") as well as between TGVI and Terasen Gas Whistler ("TGW") regarding the allocation of costs. As a result, the following sections of this document focus on the integration of TGI and TGVI and the need for shared services between those two entities. The existing agreements with TGS and TGW will continue and are therefore out of scope for this Shared Services Management Agreement.

The operational integration of TGI and TGVI facilitates a shared services approach that enables both companies to harness the benefits from economies of scale by having a single management and support structure. Common services, described summarily below, are being provided on a shared basis by the single management structure in order to meet each company's operating requirements. By restructuring the delivery of these services on a shared basis, the costs can be optimized across the entities to the benefit of all customers.

The common services that are delivered on a shared basis can be broken down into the following major functional areas:

- President's Office
- Finance and Regulatory Affairs
- Human Resources
- Operations Governance and Support
- Gas Supply and Transmission
- Business and Information Technology Services
- Distribution
- Marketing

These are described in detail in Schedule "A" of the Shared Services Management Agreement.

The benefits of providing the above noted services centrally are cost efficiency and a higher standard of service. A single management and support structure allows the companies to maintain an optimal level of resources, avoid duplication of work, and customers will benefit from synergies.

The integration process, as part of the USP, commenced in some departments effective Jan 1, 2004, and work will continue throughout 2004 and beyond to integrate technology platforms and business processes. However, it should also be noted that certain integration activities pre-dated the USP. Several agreements currently exist between TGI and TGVI for the delivery of specific services. These services include Gas Control, Core Market administration, Measurement and Instrumentation. The existing agreements for the provision of these services will continue, and are therefore out of scope for the Shared Services Management Agreement.

As noted, existing contracts with TGVI will continue in effect except for Core Market Administration. Prior to the recent restructuring, TGI provided trading and risk management services to TGVI for an annual fee of $100,000. With the recent changes, Gas Supply has assumed all gas supply related activities for TGVI and now oversees the entire cost of gas amount. As a result of this change, TGI will now charge TGVI an amount of $356,900 per annum or $29,742 per month for services relating to Core Market Administration.

6.0 Cost Allocation Approach used for Shared Services Costs

As described in previous sections of this document, the USP led to the establishment of a single management team and organization for both entities. One of the requirements resulting from the operational integration of the two companies was to establish a fair and reasonable cost allocation approach to share costs between the two regulated entities. In arriving at the cost allocation approach used, the Company drew from the report prepared by Deloitte & Touche that presents a framework based on generally accepted methods of allocating shared services costs to affiliates (filed as part of the Terasen Corporate Separation Study, Section B, Tab 9 of the 2003 Annual Review). This report was commissioned by Terasen Inc. (TI) and used in establishing the cost allocation basis for management services provided by TI to TGI commencing January 1, 2004. The framework used as the basis for the allocation of Shared Service costs is consistent with the approach used by Terasen Inc. The British Columbia Utilities Commission ("the Commission") approved the cost allocation fee to TGI in its Decision dated December 17, 2003 via Commission Order No. G-80-03.

In addition, the Company created guiding objectives for the development of cost allocation approach. These guiding objectives were to ensure:

- The avoidance of cross subsidization between regulated entities.
- The establishment of procedures that are efficient to administer and account for.
- The creation of a methodology that is reasonable, flexible and responsive to organizational changes.
- The demonstration of a causal link between the allocation of cost and the cause of the costs incurred through the use of cost drivers.

7.0 Cost Allocation Methodology

The operating expenses of each utility are comprised of direct expenses and shared services expenses. The shared service expenses relate to tasks performed centrally and the majority of costs to provide these types of services are fixed in nature. Once office facilities, staff and associated processes and systems have been established, the incremental cost to provide additional services is marginal. Providing the service centrally maximizes the utilization of the fixed costs resulting in cost efficiency. To deliver on the synergies created by this centralization, the Company moved to a shared services platform whereby the costs of management and back office support are aggregated in TGI and then allocated to TGVI.

A review of all departmental activities in the company was conducted of the common services and/or management responsibilities for operations or activities of the two entities. A determination was made of the most appropriate basis to recover costs relating to the services provided to TGVI, either through a cost allocation calculation or through a direct assignment basis utilizing timesheets.

The common services were described in summary fashion, under Section 5 above and are listed in detail in Schedule “A” of the Shared Services Management Agreement. Many of these services relate to policy, strategy and governance activities in addition to high value skills delivery in specialized areas. A significant portion of these expenses, such as human resources and regulatory support, for example, are most appropriately recovered via an allocation process. However, some of these services such as engineering services can more effectively be charged directly based on timesheet information.

All of the shared services costs were reviewed with respect to the utilization of the most appropriate allocation method and the allocation of the shared service costs to TGVI can be broken down into the following two categories, which are summarized below:

- Direct Charges - costs such as TGVI field operations costs and Commission assessment fees that can be clearly attributed to TGVI will be charged *directly* to TGVI. Support department staff including engineering, drafting, and information technology services and enterprise resource planning employed by TGI will provide services to TGVI and will charge their costs to TGVI via timesheets, consistent with the Transfer Pricing policy.

- Allocations - costs incurred in departments such as HR, Finance and Information Technology that are not involved with the direct delivery of services to end customers will be captured in departmental cost pools and then *allocated* to TGVI based on the allocation factors included in Table # 5 below:

Table # 5

COST DRIVERS	Expressed as Numbers TGI	TGVI	Total	Allocation Factors Expressed as %s TGI	TGVI	Total
Number of Customer	775,516	76,842	852,358	91.0%	9.0%	100.0%
Number of Employees (FTE/s)	1,142.2	148	1,290.2	88.5%	11.5%	100%

Based on the allocation factors described above, table # 6 below sets out the shared service costs to be *allocated* to TGVI for 2004:

Table # 6

Shared Service Costs To be allocated	Cost Driver*	Total ($000)	Allocation Factors*	Allocated ($000)
President	# of Customers	$ 1,235	9%	$ 111
Finance & Regulatory	# of Customers	5,313	9%	479
Human Resources	# of Employees	3,119	11.5%	358
Operations Governance & Support	# of Customers/# of Employees	5,732	9.7% *	557
Gas Supply & Transmission	# of Customers	2,186	9%	197
Business & IT Services	# of Customers/# of Employees	2,940	10.8% *	317
Distribution	# of Customers	4,132	9%	372
Marketing	# of Customers	4,199	9%	379
TOTAL		**$ 28,856**		**$ 2,770**

Where more than one cost driver is used, the cost pool for allocation is segregated by cost driver. The weighted average for the organizational unit is reflected in the table above.

The amount of the annual shared services cost allocation from TGI to TGVI, is estimated at $2,770,000 for 2004. This amount will be subject to a true up at year end when actual shared costs are known. The shared services allocation charges will be in accordance with the shared services agreed to in the contract. Any services not previously contemplated will be provided in a separate supplement to the agreement. The cost allocation will be updated prior to the start of each year and adjusted for changes in anticipated resource levels accordingly.

Shared service costs to be recovered by TGI from TGVI by direct charge for 2004 are estimated at $290,000. Additionally, OPEB's, which are directly attributable to TGVI staff will be allocated directly to TGVI from TGI. The allocation of OPEB's to TGVI is estimated at $151,000. The total shared service costs that will be allocated and charged directly from TGI to TGVI is estimated at $3,211,000, as set out in table # 7 below.

Table # 7

	2004 Total
Allocation of Shared Services Costs	2,770
Direct OPEB Costs	151
Direct Timesheet based Charges to O&M	290
Total Shared Services Costs – Direct and Allocated	**$ 3,211**

Appendix A

Shared Services Management Agreement

THIS AGREEMENT made as of and effective January 1, 2004

BETWEEN:

TERASEN GAS (VANCOUVER ISLAND) INC.
1675 Douglas Street,
PO Box 3777
Victoria, British Columbia
V8W 3V3

(**“TGVI”**)

AND:

TERASEN GAS INC.
16705 Fraser Highway,
Surrey, British Columbia
V3S 2X7

(**“TGI”**)

WHERAS

A. TGVI is the owner and operator of the natural gas transmission and distribution facilities in British Columbia serving the communities of Vancouver Island and the Sunshine Coast (the “Facilities”); and

B. TGVI wishes to retain TGI to provide certain administrative and management services to it in respect to the ownership and common management of the operation of operations of its transmission pipeline and distribution business on the terms and conditions set out herein.

WITNESSES that, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) “**Applicable Laws**” means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) “**Force Majeure**” has the meaning assigned to such term in Section 9.1;

(c) “**Governmental Authority**” means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) "**Services**" means the administrative and management services to be provided to TGVI by TGI as more particularly described in Section 2.1.

1.2 Schedules

The following are the schedules attached to, and are incorporated by reference into, this Agreement:

Schedule "A"	Description of Services
Schedule "B"	Pricing

1.3 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

2) any reference in this Agreement to a designated "Article", "Section" or other subdivision is to the designated Article, Section or other subdivision of this Agreement,

3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision,

4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,

5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and

6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2

SERVICES

2.1 Services

TGI hereby agrees to provide to TGVI those administrative and management services described in Schedule A.

2.2 No Obligation to Provide Additional Services

TGI shall not perform, and TGI shall have no obligation to perform, any services on behalf of TGVI in respect of the Facilities other than as set out in this Agreement or any similar agreement.

2.3 Consultation with TGVI

TGI will consult with TGVI as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between TGI and TGVI. In performing the Services, TGI shall be an independent contractor. TGI employees shall not be considered employees of TGVI for any purpose.

2.5 Compliance

In performing the Services, TGI will comply with all Applicable Laws.

PART 3

COMPENSATION

3.1 Compensation for Services

TGVI agrees to pay to TGI for the administration and management services the compensation set out in Schedule B.

3.2 Amendment to Costs

The amounts set out in Schedule "B" may be amended from time to time by agreement between the parties to reflect any material change in the cost of providing the services or in the business operations of TGVI.

3.3 Invoicing

TGI will invoice TGVI in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

(a) Except with respect to those portions of an Invoice which are the subject of a bona fide dispute between the parties, invoices shall be payable within thirty (30) days from the date of the invoice.

(b) Any amount to be remitted by TGVI to TGI and not remitted on or before the date on which it is due shall thereafter bear interest at an annual rate equal to the prime rate of interest of the Toronto-Dominion Bank (or its successor or permitted assign) (Toronto, Main Branch) plus one percent (1%) calculated daily from the date the amounts become due.

(c) Effective December 31, 2004 TGI will prepare financial accounting of the actual costs and the allocated costs, and will make adjustments based on additional amount to be paid by TGVI or return an overpayment.

(d) Payments due and owing as a result of the accounting will be paid no later then the end of the first quarter of the following year.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by TGVI

Subject to Section 4.4, TGVI will indemnify, defend and hold harmless TGI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with TGI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of TGI.

4.2 Limitation of Liability of TGI

Neither TGI nor any of its directors, officers, employees, agents or contractors will be liable to TGVI for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which TGVI may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with TGI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of TGI.

4.3 Indemnity by TGI

Subject to Section 4.4. TGI will indemnify, defend and hold harmless TGVI from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which TGVI may suffer or incur as a result of any act or omission or error of judgement as a result of which TGI is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF TGVI

5.1 Covenants by TGVI

TGVI covenants and agrees to:

(a) fully co-operate with TGI in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by TGVI to TGI or any other Person pursuant to or as contemplated by this Agreement.

PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of TGI

TGI hereby represents and warrants to TGVI as representations and warranties which are true as at the date hereof and which will be true during the term of TGI's appointment hereunder:

(a) TGI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGI has full power and authority to perform its obligations hereunder,

(b) this Agreement constitutes a valid and binding obligation of TGI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) TGI possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of TGVI

TGVI hereby represents and warrants to TGI as representations and warranties which are true as at the date hereof and which will be true during the term of TGI's appointment hereunder:

(a) TGVI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGVI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of TGVI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective retroactively from January 1, 2004 and will continue until December 31, 2004. Thereafter the Agreement will automatically be renewed for further one year terms subject to Sections 7.2 and 7.3 below.

7.2 Termination

TGI's appointment hereunder may be terminated at any time:

(a) by TGI giving TGVI written notice of such termination:

(i) if TGVI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGVI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGVI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGVI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGVI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event TGVI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGVI of written notice thereof from TGI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGI that TGVI is in breach is conceded to be correct by TGVI or found to be correct by an arbitrator pursuant to Section 8.1;

(b) by TGVI giving TGI written notice of such termination:

(i) if TGI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event TGI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGI of written notice thereof from TGVI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGVI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGVI that TGI is in breach is conceded to be correct by TGI or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Termination Without Cause

Notwithstanding Section 7.2 above either party may, upon obtaining the other party's written consent, terminate this Agreement without penalty or damages upon giving thirty (30) days written notice.

7.4 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, TGI will have no further obligations under Article 2 and will promptly deliver to TGVI any material documents in the possession of TGI pertaining to the business of TGVI.

7.5 Compensation of TGI on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, TGVI will pay to TGI all amounts owing to TGI hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this Section, the fees provided for in Article 3 which are payable to TGI on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8

ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between TGI and TGVI regarding any allegation that TGVI or TGI is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the Rules of Procedure for Commercial Mediation of The Canadian Foundation for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9

FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, “Force Majeure” shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

MISCELLANEOUS

10.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

10.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

10.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

10.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement the 31st day of May, 2004.

TERASEN GAS (VANCOUVER ISLAND) INC.

By: *Original signed by Randy Jespersen*

Title: *President*

TERASEN GAS INC.

By: *Original signed by Scott Thomson*

Title: *Vice President of Finance and Regulatory Affairs*

Schedule "A"

Description of Services

Schedule A
Services

On a shared basis, the personnel from the following departmental units of TGI will provide services

(1) **President's Office.** The role and function of the President of TGI is to provide:

(a) governance and liaisons to direct development and implementation of strategic, operational and capital plans;

(b) governance assurance that controls are in place to ensure the Company's are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(c) alignment and communication of the vision and direction to employees and other stakeholders;

(d) executive level succession planning and development to prepare and maintain exceptional leadership; and

(e) act as the principal spokesperson in maintaining close communication with government and the public.

(2) **Finance and Regulatory Affairs**. The role and function of the Finance and Regulatory Affairs department is to provide the following services:

(a) policy direction and oversight of services related to key financial areas including Strategic Planning, Regulatory Affairs, management and financial reporting, and the capital management office;

(b) oversee the understanding, communication and adherence to accounting policies procedures and practices;

(c) lead financial elements of regulatory processes;

(d) establish and execute the process for managing and facilitating the prioritization of all capital expenditures in the TGI companies through the Capital Management Office;

(e) provide high-level, strategic regulatory advice & expertise necessary to ensure the regulatory agenda/platform supports the current and future business needs of the companies;

(f) maintain/enhance the ongoing relationship that is required between TGI/TGVI (via the Regulatory Services department) and key stakeholders in the regulatory environment;

(g) regulatory support from the initial planning stage, including leading consultations with the BCUC and stakeholders and the submission of applications to the BCUC, through to the final implementation and reporting;

(h) development and maintenance of rate structures and the tariff/tariff supplements, and the analysis of cost allocation methodologies, allocated cost of service studies, for gas costs and distribution margin to support rate design applications;

(i) development of strategic and tactical aspects of regulatory platform and creation of applications for revenue requirement, PBR, ROE mechanism, SQI development. Studies and/or Applications may be directed by the BCUC or may be based on corporate strategic requirements;

(j) interpretation, education and communication of new and existing regulatory policies throughout the company, including the development and communication of a corporate regulatory policy;

(k) gathering and analysis of comparative data/competitive intelligence to assess trends within the energy industry & TGI/TGVI position relative to other utilities, particularly those within Canada and the Pacific Northwest;

(l) development of TGI/TGVI financial accounting policies and procedures;

(m) reviewing and maintaining the code of general ledger accounts;

(n) accounting for and validation of all financial statement elements including revenues, cost of gas, deferral accounts, financing costs, bank accounts, the accounting for continuing services and the billing of inter-company transactions;

(o) monthly reporting, variance analysis and year-end forecasting;

(p) external audit coordination and the preparation of non-consolidated financial statements;

(q) annual and multi-year budget processes;

(r) performance measurement and cost analysis; and

(s) asset and Plant accounting.

(3) **Human Resources**. This department is focused on providing HR services to support human resource and related business needs of the operations of the Terasen group of companies. The functional areas and the services they provide are:

(a) advice and guidance to employees and line managers on human resources management activities such as performance management, disability management, succession planning and organizational development;

(b) labour relations advice and guidance including negotiating collective agreements, contract administration and application, grievance and arbitration handling and union relations;

(c) processing activities related to costing time, pay, benefits and pension;

(d) records management and reporting; and

(e) recruitment and staffing.

(4) **Operations Governance and Support**. The role and function of the Operations Governance Support Management team is to provide the following services:

(a) policy direction and oversight of services related to key operational areas including governance of Engineering, Occupational Health & Safety, and the Environment, in addition to Emergency Planning and Public Safety;

(b) management and oversight of services related to project planning and design, system integrity, corrosion control, property services, facility records and geographical information system mapping;

(c) implementation of maintenance of management systems that control and support emergency planning, security and public safety activities to ensure compliance with applicable laws, company policy and industry codes of practice;

(d) ensuring emergency response plans are maintained, updated and tested on a regular basis;

(e) working with governmental and non-governmental agencies to develop and coordinate emergency response protocols;

(f) coordinating the development of security standards and programs to protect TGI facilities and assets;

(g) coordinating and implementing a public safety awareness program and standards to ensure an appropriate level of public safety communication and program delivery to meet "duty of care" and "duty to warn" due diligence;

(h) delivering trades training services to key operations groups within the utility to maintain skill competencies and ensure compliance with laws, policies and industry codes;

(i) maintenance of employee training records;

(j) corporate governance of management systems controlling environmental affairs, employee occupational health & safety, and the design, construction and operation of the gas pipeline system;

(k) monitoring and reporting of compliance with all applicable laws, company policies and industry codes of practice;

(l) advice and direction to Operations groups in support of their accountability to manage specific Environment, Health & Safety risks;

(m) managing a common standards framework to ensure environmental compliance, a safe working environment for employees and consistent, efficient application of standards;

(n) ensure that the workforce meets Workers Compensation Board legislative requirements;

(o) uphold customer and public expectations regarding environmental due diligence and habitat preservation;

(p) responsible for project management and professional services to meet the requirements of managers;

(q) responsible for developing and maintaining a comprehensive Integrity Management Plan for the gas distribution and transmission operating plant assets. Also provides risk-based integrity management services related to operating plant and surrounding natural hazards, principally focused on material defect, corrosion, geotechnical and hydro-technical risks;

(r) responsible for Operation and Maintenance of systems providing cathodic protection to operating plant;

(s) responsible for the planning of lowest cost system improvements for the gas Distribution and Transmission systems, as well as hydraulic scenario analyses for operational enquiries and project development;

(t) responsible for managing all land rights and land tenure issues including property taxation, acquisition & disposal, leases, right of way agreements, environmental reviews and first nations negotiations;

(u) responsible for maintenance and security of all pipeline rights of way; this includes third party crossing permits & inspections, sub-division approvals, vegetation management, right of way patrol, public awareness and encroachment removal;

(v) responsible for completing new mains and service construction drawings and as-built mapping, as well as detailed design drawings for engineering projects as required by the Distribution and Transmission asset managers;

(w) responsible for final data integrity checking of field drawings prior to data entry in the Geographic Information System;

(x) responsible for developing and maintaining the Geographic Information Systems (GIS), and maintaining all records for Distribution and Transmission facilities; and

(y) Responsible for providing Location Records information for underground facilities, as requested through BC One Call.

(5) **Gas Supply and Transmission ("GS&T")**. GS&T provides policy direction and oversight services in addition to business performance management related to key operational areas. The GST department is responsible for:

(a) gas supply which secures the commodity (gas or propane) and ensures it gets to TGI's Transmission network;

(b) transmission which moves the gas to TGI's Distribution network and also manages LNG storage;

(c) business development which ensures that, at a regional level, appropriate capacity and capabilities are available to serve current and future consumers of natural gas;

(d) ensuring there are reliable and secure peaking supplies of natural gas for all core customers at an optimum cost;

(e) arranging natural gas supply to firm and interruptible customers on the distribution system;

(f) providing intra-day balancing supply to stabilize the pressures on the TGI distribution system;

(g) facilitating all gas scheduling and nominations on TGI and third party transmission systems and on the TGI distribution system;

(h) optimizing the value of the natural gas supply portfolio for the benefit of customers on the TGI system;

(i) managing relationships with upstream pipeline companies (Duke, TCPL) to the benefit of TGI's customers;

(j) developing natural gas and propane portfolios for TG and TGVI (Annual Contract Plans);

(k) evaluating supply and asset options (Send out Model);

(l) price risk management for TGI and TGVI;

(m) portfolio and price risk analysis for Gas Supply and Business Development;

(n) provision of Market Information;

(o) execution of the Annual Contract Plans (Resource Stack) to meet core demand in a cost effective manner;

(p) execution of financial hedging transactions;

(q) managing issues upstream/downstream of TGI/TGVI facilities and building relationships with PNW participants;

(r) managing relationships/service delivery with EMS/Transmission customers;

(s) compliance functions;

(t) regional resource planning and other forecasting needs;

(u) maintaining regulatory relationships regarding ongoing Transmission asset management, and managing Transmission safety and pipeline integrity programs;

(v) developing and championing the regional natural gas infrastructure strategy;

(w) identifying, evaluating and developing appropriate growth opportunities; and

(x) managing major third-party transmission shipper relationships.

(6) **Business and Information Technology Services**. This Division provides business services, information technology application and infrastructure management services which enable the operating areas of the company to provide the delivery of utility services. The Division's focus is company-wide and broad in scope.

(a) Policy direction and oversight of services related to key support areas including Business services which is comprised of Facilities services, Purchasing and accounts payable.

(b) Management and oversight of services related to information technology application and infrastructure management services.

(c) Procurement for materials and services.

(7) Accounts Payable.

(a) The accounts payable group is responsible for ensuring vendors are paid accurately and in a timely manner.

(b) Provides administrative support for corporate credit card program.

(c) Facilities Management Services has responsibility for all TGI buildings throughout the service territory. It provides building equipment maintenance, security services and cleaning services. It also arranges and negotiates new space requirements and telecom requests for the organization.

(8) IT Services.

(a) Application Management Services manages the overall data and application architecture for TGI and provides application integration design and delivery services. It is a joint custodian of the TGI Technology Architecture Standards.

(b) Provides application architecture and technology consulting services and ensures application projects are developed according to TGI technology standards.

(c) IT Infrastructure Management plans, forecasts, and designs for future infrastructure capacity requirements and develops and directs the implementation of new technology services at TGI. It is a joint custodian of the TGI Technology Architecture Standards.

(d) IT Infrastructure Management ensures the availability, integrity and security of TGI critical enterprise infrastructure, including: Wide Area Network (WAN), distributed applications/systems, desktop and mobile computer devices, and outsource management.

(9) **Distribution.** The role and function of the Distribution business unit is to provide the following services:

(a) policy direction and oversight of services related to key operational areas including Distribution operations and maintenance, Emergency Management Services, Account Services and Fieldwork, Distribution Operations Support, Measurement Technologies, and Shops, Inventory and Trucking;

(b) general management and oversight of services are focused on delivering a safe, reliable and cost-effective gas distribution system for residential, commercial and industrial customers;

(c) regional managers and front line field Operations and Install managers who are responsible for day-to-day operations in specific geographic areas;

(d) responsible for ensuring that materials and services are manufactured, tested for fitness of use, and distributed to TGI operating and support groups;

(e) measurement technologies is responsible for maintaining the accuracy of metering devices as well as providing energy consumption data to large commercial and industrial customers; and

(f) provide fabrication of critical system components that are installed in the distribution system.

(10) **Marketing**. The primary responsibilities of Marketing are to manage relations with all customer groups and stakeholders; to produce energy use and account growth forecasts; and to manage TGI's internal and external communications requirements. Marketing provides an organizational focus in the management of these responsibilities and in the delivery of marketing services.

Marketing services provided through TGI to TGVI on a shared service basis fall into the following service areas:

(a) responsibility for providing overall policy direction and oversight of services relating to the marketing function, including overseeing the development and implementation of marketing initiatives and programs;

(b) provide overall policy direction and oversight of services relating to residential and small commercial markets;

(c) provides overall policy direction and oversight of services relating to large commercial and industrial markets;

(d) planning and delivery of customer education and communication, product development, and market research;

(e) program development, carries out trade relations activities, manages customer connection policies, and produces marketing communications;

(f) deals with escalated calls from the call centres;

(g) creates messaging for customer education and communication on the topics of rate changes, natural gas prices, competition with alternative fuels, billing issues, customer connection policies and regulatory changes (e.g., gas cost increase, rate design changes);

(h) provides market research activities focus on customer research (e.g., end-use studies), customer satisfaction, safety, and attitudes and opinions around Company initiatives;

(i) oversees both the Main Extension test, and the Company's service line policies;

(j) evaluates existing offerings to determine if they represent the right mix of customer service and core market cost recovery and the design, negotiation and submission of new an amended services to the British Columbia Utilities Commission;

(k) develops customer energy use and customer additions forecasts;

(l) provides analysis and decision support on longer-term supply/demand and pricing issues, and performs portfolio modeling;

(m) provides overall policy direction and oversight of services relating to TGVI's community and aboriginal relations requirements; and

(n) provides internal and external communications services for the Company, including employee communication and media relations.

Schedule “B”

Pricing

Schedule B
Estimated Pricing

Shared Services Costs to be Allocated	Cost Driver	Annual Total ($000)	Allocation Factors	Allocated ($000)
President	# of Customers	$1,235	9%	$111
Finance & Regulatory	# of Customers	5,313	9%	479
Human Resources	# of Customers	3,119	11.5%	358
Operations Governance & Support	# of Customers/ # of Employees	5,732	9.7%	557
Gas Supply & Transmission	# of Customers	2,186	9%	197
Business & IT Services	# of Customers/ # of Employees	2,940	10.8%	317
Distribution	# of Customers	4,132	9%	372
Marketing	# of Customers	4,132	9%	379
TOTAL		**$28,856**		**$2,770**
Annual Monthly Allocated				**$230.833**

Note the annual allocated amounts shown in this chart are proforma estimates that are subject to year end true-up.

TERASEN GAS INC.

REPORT ON THE ESTABLISHMENT OF INCENTIVE MECHANISM FOR REDUCING UNCONTROLLABLE / PARTIALLY CONTROLLABLE EXPENSES FOR THE YEAR ENDING DECEMBER 31, 2004

1. PROPERY TAX

The 2004 – 2007 Multi-Year PBR Settlement addresses the issue of establishing incentive mechanisms for Terasen Gas for reducing uncontrollable or partially controllable costs.

The Negotiated Settlement, Appendix A to BCUC Order No. G-51-03, indicates that the Company is to have a positive incentive around provincial and municipal government taxes, fees and expenses and that a specific mechanism was agreed to regarding property taxes.

For purposes of determining the incentive, property taxes are divided between the 1% In-Lieu taxes and all other categories of property taxes. The other property taxes include General, School, First Nations, and other taxes, and will herein be referred to as Other Property Taxes.

With respect to the 1% In-Lieu taxes, the Company is entitled to keep 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.

For the Other Property Taxes, a modified version of the formula-based approach applicable to O&M expenses and net gas plant in service will be applied. The 2003 actual amount forms the base to which 2004 customer growth, inflation, and inflation offset factors will be applied to determine the target for 2004. The Company will be entitled to 10% of the amount by which its actual taxes are lower than the target.

The 2004 target has been calculated as:

$25,160,000 x (1+ 1.15%) x (1 + 1.70% - 0.85%) = $25,666,000

The 2004 Other Property Taxes total is projected to be $25,764,000, which is higher than the 2004 target of $25,666,000 (Table A). Since the projected 2004 property taxes are higher than the target, the Company will not be entitled to any incentive based upon the 2004 results. However, it is important to note that had Terasen Gas not realized the property tax savings due to our mitigation efforts, the 2004 actual property taxes would have been higher by $160,900.

If Terasen Gas is successful with current mitigation efforts, future property tax savings could reach $596,000 (see Summary on Page 4 of this Tab for details).

Table A

	2003 Actual	Change	2004 Projection	2004 Target
Average Number of Customer	770,624	8,874	779,498	
Percentage Growth in Average Customers		1.15%		
Annual Inflation Rate - CPI		1.70%		
Adjustment Factor		0.85%		
Property Tax ($000)				
1% in Lieu	$14,152		$13,016	
Other Property Taxes	25,160		25,764	$25,666
Total	$39,312		$38,780	

Background Details behind Property Tax Cost Mitigation Plans

The 2004 property tax mitigation plans were based on preemptive strategies by Terasen Gas; with the goal of minimizing property tax increases and cost pressures to customers. The savings summarized below are based on actual performance or are based on current ongoing mitigation activities. Unrealized future savings relate to issues that are either before the Property Assessment Appeal Board or where Terasen Gas is awaiting decisions from either the Indian Taxation Advisory Board (“ITAB”) or BC Assessment.

Mitigation Activities:

1. **Transportation Pipeline Rate Correction** – Terasen Gas discovered an error in the 2004 legislated pipeline rates. An agreement was reached with BC Assessment to correct only the largest error in 2004 (6” pipe), and to adjust the 2005 rates to ensure that the overall assessment over the two years would be as originally agreed upon. The tax savings based on the actual tax notices amounted to $67,870.37.

2. **Tower Appeal** – An appeal was launched in 2004 with respect to the valuation of communication towers owned by Terasen Gas. BC Assessment agreed to review their valuation methodology on towers, and the appeal was subsequently withdrawn based on an understanding with BC Assessment that corrections would be processed once their review was complete. Discussions with BC Assessment indicate that Terasen Gas could expect reductions on the overall assessment value of our towers around 40 to 50%. At the present time only one tower has been adjusted, resulting in a savings of $2,218.20. Based on the above, we are expecting a further annual reduction of approximately $12,000.

3. **Office Appeal** – An appeal was undertaken in 2004 on all Terasen Gas offices. The Company is presently awaiting the outcome of an appeal which is before the BC Court of Appeal, and is expected to be heard in November of 2004. Potential annual savings from this appeal are estimated to be $584,000.

4. **Tax Rate Error** – A refund of $84,224.51 was received from the City of Vernon. The refund was issued after Terasen Gas identified a tax calculation error based on the City of Vernon 2004 Tax Bylaw.

5. **Miscellaneous Appeals** – The Company achieved a further reduction of $6,624 through various other appeals on valuation and classification.

6. **Other Activities** – Terasen Gas continues to be involved with a variety of groups specializing in Local Government taxation, these include the Canadian Property Tax Association, the Vancouver Board of Trade, and the Canadian Energy Pipeline Association. In addition, Terasen Gas has been invited to sit on at least two committees within the Provincial Government that are currently reviewing various Local Government Taxation tools.

Summary

Actual savings in 2004

1.	Transportation Pipeline	$ 67,900
2.	Tower Appeal	2,200
3.	Tax Rate Error	84,200
4.	Other Appeals	6,600
Total Actual 2004 Savings		**$160,900**

Mitigation Measures in Progress

1.	Office Appeal	$584,000
2.	Tower Appeal	12,000
Total Mitigation Measures in Progress		**$596,000**

2. UTILITY ASSET UTILIZATION PROPOSAL UPDATE

In 2003 Annual Review, Terasen Gas detailed how there may be opportunities to generate revenue from the sale of space in distribution pipe for the placement of fiber optic cable. By way of background, technology exists that allows fiber optic cable to be safely placed in natural gas distribution pipelines while the pipe continues to carry natural gas. In some urban situations, it may not be economically feasible for telecommunications companies to lay fiber optic cable in a traditional manner. Placing fiber optic cable in gas pipelines gives the telecommunications companies an alternative to traditional methods.

Terasen Gas explored options for this service but concluded that in the current environment, the service was not economically feasible. Terasen Gas has no current plans to pursue fiber in gas pipeline service but would consider it should the right opportunity present itself.

TERASEN GAS INC.

CODE OF CONDUCT AND TRANSFER PRICING POLICY
REVIEWS CONDUCTED BY INTERNAL AND INDEPENDENT EXTERNAL AUDITORS

The Commission stated, at page 21 of Appendix A to Commission Order G-51-03, the following relating to compliance with the 2004-2007 Negotiated Settlement:

> *"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."*

The Internal Audit Services has prepared such a report and is attached as Appendix A to this Section B-6.

Furthermore, the Commission continued to state at page 22 of Appendix A:

> *"In addition, before the first Annual Review, Terasen Gas' independent external auditor will review the work performed by Terasen Gas' Internal Audit Services……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."*

On June 22, 2004, Terasen Gas submitted to the Commission a request to discontinue the services of the independent auditor as they relate to the Code of Conduct (CoC) and Transfer Pricing Policy (TPP) compliance. In Commission Order L-33-04, dated July 5, 2004, the Commission concluded that "…the external auditor should carry out another review of TGI's compliance with the CoC and the TPP prior to TGI's next Annual Review."

As such, Terasen Gas has once again contracted the services of the firm KPMG to provide a review of and report on Terasen Gas' compliance with the CoC and the TPP. KPMG's report is attached as Appendix B.

Based on their respective review procedures, both internal and external auditors concluded that nothing came to their attention that would cause them to conclude Terasen Gas is not in compliance with either of the CoC and TPP.

SECTION B-6 CODE OF CONDUCT AND TRANSFER PRICING POLICY COMPLIANCE

ATTACHMENT A – INTERNAL AUDIT REPORT

Doug Cruickshank
Director, Internal Audit Services

16705 Fraser Highway
Surrey, BC V3S 2X7
Tel: 604-592-7927
Fax: 604-592-7620

October 8, 2004

Mr. Randy Jespersen
President, Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C. V3S 2X7

Dear Sir:

Subject: Annual Review of Compliance with the Terasen Gas Inc. Code of Conduct and Transfer Pricing Policy.

Internal Audit Services (IAS) has completed a review of compliance with the Terasen Gas Inc. (TGI) Code of Conduct and Transfer Pricing Policy for the Provision of Utility Resources and Services (Policies). This review is conducted to satisfy TGI requirements as documented in the Policies.

> "TGI will monitor employee compliance with the Code of Conduct by conducting an annual compliance review, the results of which will be summarized in a report to be filed with the Commission (B.C. Utilities Commission) within 60 days of the completion of this review." [1]
>
> "The Transfer Pricing Policy will be reviewed on an annual basis as part of the Code of Conduct compliance review." [2]

Background

The Policies were issued in August 1997 to provide guidance to TGI employees on interactions with Non-Regulated Business (NRB). NRBs are defined as: "an affiliate of the Utility not regulated by the Commission or a division of the Utility offering unregulated products and services[3]". TGI has processes and practices that are designed to ensure compliance with these Policies.

Commission approval was obtained in July 2003 for the TGI Settlement Agreement for a 2004 - 2007 Performance-Based Rate Plan. One of the conditions for compliance with this negotiated settlement is that:

> "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.

[1] Item 2 Compliance and Complaints, Code of Conduct
[2] Item 8 Review of Transfer Pricing Policy, Transfer Pricing Policy
[3] Item 3 Definitions, Code of Conduct

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 Policy Pricing.[4]"

Review Objective and Approach

Objective:
Consistent with prior years, the objective of this review is to determine whether the existing processes and practices that support compliance with the Policies are adequately designed and operating effectively during the period under review.

Approach:
Our review of business processes and practices that support compliance with the Policies is made in accordance with Canadian generally accepted standards for review engagements as set out in the Canadian Institute of Chartered Accountants Handbook. In addition to enquiry, analytical procedures and discussion that we deemed necessary, we carried out the following:

- Read the Code of Conduct and the Transfer Pricing Policy.
- Made enquiries concerning the information maintained by TGI to monitor its compliance.
- Observed and tested the processes and practices that support compliance with the Policies.

Conclusion

Based on my review, nothing has come to my attention that causes me to believe that Terasen Gas Inc. is not in compliance with the Code of Conduct and Transfer Pricing Policy for the period January 1, 2004 to August 31, 2004.

Specific Matters

1. Our recommendation last year that all computer users acknowledge understanding and compliance with the Code of Conduct and Transfer Pricing Policy on a quarterly basis through a user acceptance screen during the network login process is operating effectively.

2. Our survey of a representative sample of TGI employees identified a small minority of temporary or newly hired employees (3) who report being unaware of the Policies. These staff did not perform NRB work and, more importantly, our internal control that requires managerial approval of time sheets to detect and correct such an error, if it did occur, was operating effectively.

   Remedial action:
   At management's request we advised these individuals directly of this requirement and management is currently reviewing orientation processes and practices for update and improvement.

[4] Page 21 & 22, Appendix A, BCUC Order G-51-03

We thank management and staff for their assistance and co-operation during our review.

Doug Cruickshank, CA*CISA
Director, Internal Audit Services

cc: John Reid, CEO
Steve Richards, General Counsel, Chief Risk Officer and Corporate Secretary
Scott Thomson, Vice President, Finance & Regulatory Affairs, Terasen Gas Inc.
Guy Elliott, Partner, KPMG LLP

SECTION B-6 CODE OF CONDUCT AND TRANSFER PRICING POLICY COMPLIANCE

ATTACHMENT B – EXTERNAL AUDIT REPORT

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Canada

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REVIEW ENGAGEMENT REPORT

Mr. Scott Thomson
Vice President of Finance and Regulatory Affairs
Terasen Gas Inc.

We have reviewed Terasen Gas Inc.'s compliance as at and for the eight months ended August 31, 2004 with its Transfer Pricing Policy For Provision of Utility Resources and Services (the "Transfer Pricing Policy") and the Code of Conduct For Provision of Utility Resources and Services (the "Code of Conduct"), both dated August 1997. Our review was made in accordance with Canadian generally accepted standards for review engagements and accordingly consisted primarily of enquiry, analytical procedures and discussion related to information supplied to us by the Company, including a review of Terasen Gas' Internal Audit Services report on compliance with the Transfer Pricing Policy and Code of Conduct dated October 8, 2004 and their work performed in connection with the report.

A review does not constitute an audit and consequently we do not express an audit opinion on this matter.

Based on our review, nothing has come to our attention that causes us to believe that the Company is not in compliance with the Transfer Pricing Policy and Code of Conduct referred to above.

KPMG LLP

Chartered Accountants

Vancouver, Canada
October 28, 2004

1. COASTAL FACILITIES PROJECT – VARIABLE INTEREST ENTITY

Background

The Coastal Facilities Project involved the construction of new facilities to replace two buildings in Burnaby (Lochburn) deemed to be structurally deficient and unsafe and to alleviate the overcrowding conditions at the Surrey (Fraser Valley) office. Instead of funding the project through traditional means, Terasen Gas developed an innovative technique referred to as a synthetic lease for the funding of the Coastal Facilities Project, in order to reduce the revenue requirement impact of the Coastal Facilities Project to customers. Because the synthetic lease structure achieved off-balance sheet accounting treatment at the time, the Company was able to finance the project outside of rate base with 100% debt. This structure was proposed by the Company on the basis that it offered a significant benefit to customers, while doing no harm to shareholders, because of the off-balance sheet nature of the financing. At the time (prior to the Enron bankruptcy), investors and credit rating agencies were generally not concerned about off-balance sheet financing arrangements. The Company therefore believed that the 100% off-balance sheet debt financing of the project would not have an impact on how investors and rating agencies perceived Terasen Gas.

To accomplish this, the BCG Coastal Facilities Trust (the “Trust”) was set up to facilitate the synthetic lease arrangement. To manage the interest rate risk on the financing, the Trust entered into interest rate swap agreements maturing on November 30, 2007.

When the synthetic lease structure was originally proposed, the Company noted the risk that accounting or tax rules could change over time, which could adversely impact the Company’s shareholders. Accordingly, Terasen Gas sought and received Commission assurance that the Project may be financed as a traditional rate base item in the event of such a change. BCUC Order Number C-14-98 states that “***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.***” This arrangement generated significant customer benefits with minimal impact to Company shareholders. Terasen Gas has determined that the benefit enjoyed by customers since the inception of the lease amounts to some $6 million as the facilities have been fully financed through a synthetic lease and have attracted no return on equity in customer rates.

Current Developments

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 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. This means that the synthetic lease in place to finance the Coastal Facilities project will need to be recorded in the Company's balance sheet and no longer be treated as an operating lease effective January 1, 2005.

Since Terasen Gas is no longer able to keep the synthetic lease off its balance sheet effective January 1, 2005, the Company is required to increase common equity by $16.7 million representing 33% of the $50.3 million outstanding balance of the Coastal Facilities Project in order to maintain the allowed capital structure of 33% equity and 67% debt. The incremental equity will earn the approved return on equity (currently 9.15%). In absolute dollars, the amount available to shareholders will increase accordingly; however on an earnings per share basis the shareholder of Terasen Gas will not be impacted positively or negatively since additional shareholders equity of $16.7 million will have to be in Terasen Gas due to this accounting change. This is consistent with BCUC Order Number C-14-98 which states that "***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.***" The unwinding of the Coastal Facilities lease is no different that any other investment Terasen Gas makes in plant facilities and as such, should be afforded comparable treatment.

On August 16, 2004, Terasen Gas applied to the BCUC for approval to include the Coastal Facilities assets in rate base effective January 1, 2005, given that this issue had been raised on a number of occasions in previous submissions to the BCUC and interested parties. In Letter L-50-04, the BCUC directed that deferral of the application to the Annual Review in November 2004 would be appropriate.

Given these circumstances, Terasen Gas has included the Coastal Facilities assets in rate base effective January 1, 2005 in this Annual Review filing. The Company expects to collapse the current lease arrangement and finance the Coastal Facilities assets with a conventional mix of debt and equity, as the cost of debt in the synthetic lease is moderately higher than the cost of debt achievable through the issuance of conventional debt.

Terasen Gas proposes 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 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. The assumption of the rate swap arrangement by Terasen Gas 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 around $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 transfer to rate base at January 1, 2005 an estimated $50.3 million representing the outstanding balance of the Coastal Facilities Project. It is proposed that the depreciation of the Coastal Facilities assets be 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 (details below).

Although the Coastal Facilities Lease is an operating lease for accounting purposes, it is treated as a capital lease for tax purposes and takes on the nature of a capital asset for income tax purposes. Accordingly, the CCA deductions related to the Coastal Facilities Project has been included in Terasen Gas' yearly utility tax calculations since the inception of the lease.

The Commission, via Letter L-50-04, requested an analysis of what the financial impact of the Coastal Facilities would be if AcG-15 was adopted, was not adopted, and if variance from GAAP was ordered.

The Company is obliged to comply in its financial reporting with AcG-15 as a core component of Generally Accepted Accounting Principles. Failure to comply with the pronouncements would also result in a material misstatement of the financial position of the Company that would result in a qualification of the Auditor's opinion on the financial statements of the company. It would result in a default under the Company's credit facilities and also result in both Terasen Gas Inc. and Terasen Inc. being designated as defaulting issuers by Canadian securities exchanges, resulting in a suspension of trading in Terasen Inc. shares on those exchanges and denying both Companies access to debt and equity financing. As the Company is obliged to comply with AcG-15, the financial impact of not adopting AcG-15 has not been analyzed.

If the Commission chose to order a variance from GAAP for regulatory purposes, it could do so by ordering that the synthetic lease be preserved and operating lease treatment be used for the determination of revenue requirements. This would essentially be the preservation of the status quo for customers, but would not accord with the statement in Order C-14-98 that said the Company shareholders will be protected from the impact of changes to accounting rules. The Company would be expected (by credit rating agencies and investors) to have shareholders' equity supporting the assets transferred to rate base, but the continuation of synthetic lease would mean that shareholders would not earn return on the equity supporting the Coastal Facilities assets.

However, as noted previously, the synthetic lease is a relatively more costly form of borrowing compared to conventional debt financing. If the Commission chose to preserve 100% debt financing for the Coastal Facilities assets, the lowest-cost way to do so would be to include the Coastal Facilities assets in rate base, but order that they be financed with a deemed capital structure of 100% debt. This would in fact result in a net cost reduction to customers compared to the synthetic lease as a result of the use of 100% conventional debt financing. Such an approach would have a similar adverse impact on the Company's shareholders and on investor and rating agency perceptions as ordering the continuation of operating lease treatment under the synthetic lease, because under either scenario, the Coastal Facilities assets would effectively be financed for ratemaking purposes with 100% debt. Although the Company does not believe that 100% debt financing for the Coastal Facilities assets is appropriate or fair to the

Company or its shareholders, preserving the synthetic lease would be the least efficient way to retain 100% debt financing for ratemaking purposes.

The following table outlines the financial impact of this analysis. It assumes, for the purposes of this analysis, that the required return for equity investors is equal to the return allowed by the Commission, so that earnings equal to the allowed return and produce neither gains nor losses for shareholders.

					Financial Impact of Coastal Facilities	
					Shareholders	RatePayers
AcG-15 Is Adopted						
Coastal Facilities Assets in Rate Base, 67% Debt Financing						
Unwind the synthetic lease						Capital
Cost of common equity	$	16,599	X	9.15%	$ (1,519)	$ -
Shareholder return	$	16,599	X	9.15%	1,519	(2,319)
Debt cost - blended	$	50,300	X	6.10%		(3,066)
Avoided debt	$	(16,599)	X	4.00%		664
Depreciation exp	$	50,300	X	1.50%		(1,152)
LCT	$	50,300	X	0.175%		(134)
Avoided lease cost						4,954
					$ -	$ (1,053)
(assumes that the cost of equity for shareholders is in fact 9.15%)						
Variance from GAAP Is Ordered						
Preserve Operating Lease Treatment for Regulatory Purposes						Operating lease
Retain the synthetic lease						
Cost of common equity	$	16,599	X	9.15%	$ (1,519)	
Return on avoided debt	$	16,599	X	4.00%	$ 664	
Tax on avoided interest	$	664	X	34.5%	$ (229)	
					$ (1,084)	$ -
Variance from GAAP Is Ordered - Alternate						
Coastal Facilities Assets in Rate Base, 100% Debt Financing						
Unwind the synthetic lease						Capital
Debt cost	$	50,300	X	6.1%		$ (3,068)
Depreciation exp	$	50,300	X	1.50%		(1,152)
LCT	$	50,300	X	0.175%		(134)
Avoided lease cost						4,954
Shareholder impact per above					$ (1,084)	
					$ (1,084)	$ 599

In accordance with Commission directions, and in order to meet the expectations of credit rating agencies, the Company has maintained over time its allowed capital structure of 33% equity and 67% debt supporting rate base. When the synthetic lease was established, the Company agreed that the Coastal Facilities project could be financed outside of rate base with 100% debt within the synthetic lease, because the debt would not appear on the Company's balance sheet and therefore the debt ratio reported in the Company's financial statements would be preserved.

Since the synthetic lease is effectively financed with 100% debt, on-balance sheet accounting for this obligation will result in the Company's debt ratio exceeding the levels presently authorized by the BCUC and expected by credit rating agencies and investors. In order to restore the Company's debt ratio to levels expected by credit rating agencies, the Company will need to issue or retain additional common equity. Unless the Coastal Facilities assets are included in rate base, with an allowed return based on 33% equity and 67% debt, the Company will be penalized by having to maintain common equity on which it is not permitted to earn an appropriate return. Terasen Gas already has one of the lowest deemed equity components in the country, and credit rating agencies have expressed their concern numerous times about this issue. A decision by the Commission that the Coastal Facilities assets should be financed with 100% debt prospectively would be perceived by credit rating agencies and investors as a willingness on the Commission's part to further reduce the equity component of Terasen Gas' deemed capital structure. Effectively, such a decision would reduce the deemed equity component of Terasen Gas to approximately 32.3%. Investors and credit rating agencies would find such a signal surprising and troubling. The result would likely be higher borrowing costs, which would harm both customers and shareholders. Further, the Company submits that a change to the Company's deemed capital structure should not be made in the context of a change in accounting rules, but rather should only occur after a full review of capital structure and allowed returns. Further, a reduction in the deemed equity component needs to consider the signal such a decision would send to credit rating agencies and investors, who are already sensitive to Terasen Gas' relatively low deemed equity component compared to other U.S. and Canadian utilities.

The Company submits that including the Coastal Facilities assets in rate base with a conventional mix of 67% debt and 33% equity is consistent with Commission Order C-14-98, treats the customers fairly, and protects the Company's shareholders from the adverse impact of accounting changes as contemplated by the Order.

2. CUSTOMER SECURITY DEPOSITS

As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of Terasen Gas is required to provide a security deposit. Due to the increase in commodity prices of natural gas over the past few years, Terasen Gas has experienced a significant increase in the number of meter lockoffs and a corresponding increase to customer security deposits. For 2005, the level of customer security deposits is forecast to be $23 million on average.

In accordance with the General Terms and Conditions of the Terasen Gas Tariff, the Company is required to pay interest on Customer Security Deposits at prime interest rate minus 2%. Because historical customer deposits were not material, customer deposits were treated, in effect, as an "interest free" source of working capital for regulatory rate setting purposes. The interest paid to customers of approximately $100,000 per year was absorbed by the Company and was never part of past revenue requirements.

Given the size of the projected 2005 customer security deposits, Terasen Gas proposes to establish a regulatory treatment that is fair to all parties involved. Accordingly, the following regulatory options have been identified for consideration:

1. Keep the $23 million in a separate bank account and have it self funding. Currently, interest earned on bank deposits is equal to the prime rate less 2.0%, the same rate that is paid on security deposits. Therefore the account will be self funding and will have no impact on existing customers or shareholders.

2. Use the $23 million as a substitute in place of short-term borrowing requirements from traditional financial markets. Since interest rate on security deposits is expected to be lower than that obtainable from traditional source, existing customers can expect to benefit from lower interest cost. For example, for the first nine months of 2004 conventional short-term debt financing cost the Company on average 1.1% lower than the prime rate. Given that the rate paid on security deposits is 2.0% less than prime, this would result in a net saving in interest of $207,000 ($23 million X 0.9%) for existing customers. So by accessing customer security deposits to fund working capital, it lowers the effective borrowing cost for existing customers.

The first option keeps all parties whole and does not negatively nor positively impact existing customers. Under the second option, Customers who provided the security deposit will continue to receive interest as prescribed in accordance with the Terasen Gas Tariff, shareholders will not be negatively impacted through unrecoverable interest cost, and existing customers will be provided with a source of working capital that has a lower cost than what Terasen Gas can borrow at through the traditional source.

In keeping with the spirit of the Settlement, Terasen Gas will honor the commitment to the continuation of the interest free status on the $2.6 million of customer security deposits that was embedded in the negotiated settlement. In other words, existing customers will enjoy the benefits of not having to pay interest on the $2.6 million through their rates until the end of 2007.

The balance of the customer security deposits will have effectively substituted what would have been short-term debt, so it makes sense to include customer deposits in the capital structure, similar to short-term debt, with a cost component equivalent to prime minus 2% to recover the incurred interest from customers. To keep the capital structure simple, Terasen Gas proposes to combine the incremental customer security deposits with short term borrowings in the capital structure. This has the added benefit of providing deferred interest protection for customers and shareholders as the impact of forecast interest rate variations will be captured via the interest deferral account.

In summary, Terasen Gas recommends keeping the interest free status of the $2.6 million security deposit that was included in the negotiated settlement, but opt for the second option treatment for the incremental security deposit funds since it balances the notion of fairness and offers the greatest benefits to all parties. Accordingly, the recommended treatment has been reflected in the financial schedules included in this Application.

3. DISCLOSURES BY ENTITIES SUBJECT TO RATE REGULATION

In October of 2004, the Canadian Institute of Chartered Accountants (CICA) issued a Draft Guideline "Disclosures by Entities Subject to Rate Regulation". If approved, this Guideline would be applied to financial reporting for the Second Quarter of 2005. The main features of the proposed Guideline are:

- Disclosure of general information on rate regulation and its accounting effects;
- Disclosure of additional information on specific items affected, including their financial statement treatment, the financial statement effect of differences from Generally Accepted Accounting Principles, and specific information on any assets or liabilities recognized as a result of rate regulation;
- Guidance on the format of the disclosures above;
- Balance sheet presentation requirements that assets and liabilities (including those that are rate-regulated) should not be offset, unless specifically permitted by another Section or Guideline.

This Draft Guideline is not expected to have a significant impact on the Company's financial statements; however, the final Guideline may include requirements to change accounting treatment in the future.

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
MISCELLANEOUS INFORMATION PERTAINING TO THE SETTLEMENT

The following materials deal with (4) matters:

A. Core Administration Budget 2004

B. Customer Advisory Council Meetings

C. Customer Growth Strategy – New Residential Markets

D. Exogenous Factors

A. CORE ADMINISTRATION BUDGET 2004

In response to Commission Order G-19-04 and Commission letter dated April 13, 2004, Terasen Gas provides this review of the 2004 Core Market Administration Expenses as well as the proposed expenses for 2005. Terasen Gas is seeking approval of

- The proposed 2005 TGI net Core Market Administration Expense of $1.892 million; and
- The proposed Core Market Administration Revenue sharing approach.

As a result of the 2004 amalgamation of Terasen Gas and TGVI operations, a single Gas Supply department was formed to supply all Terasen Gas utility operations (Terasen Gas, TGVI, TGW, and TGS; collectively the “TGI System”) with gas supply management functions. Gas supply management functions are funded by cost of gas as Core Market Administration Expense.

Managing both natural gas and propane requirements, the key functions performed by the Gas Supply department are to:

- provide reliable, secure supply of natural gas and propane to Core customers from a complex portfolio of supply options to the TGI System,
- develop and implement the Annual Contract Plan and the Price Risk Management Plan,
- execute resource stack to meet core demand and balance customer transport loads,
- facilitate all gas nominations for the TGI System, and
- manage the Midstream and Commodity portfolios as it relates to the Essential Services Model implemented as part of the Unbundling project.

As part of the above key functions, Gas Supply Activities include but are not limited to: regional supply and demand analysis, development of annual contracting plan, negotiation, and administration of pipeline storage and commodity contracts, regulatory reporting, budgeting and cost accounting functions, optimization planning of storage and pipe assets, daily load estimation and supply optimization, trading and asset mitigation, development of price risk management plans, implementation of financial derivatives, formalization of ISDA contracts and credit review, back office compliance review, upstream strategy and relationship management, retail unbundling development, new regional infrastructure proposals and regional pipeline rate design interventions.

2004 Commission Approved Funding

For 2004, the Terasen Gas net core expense was set to the 2003 amount. The Commission letter dated February 23, 2004 acknowledged that 2004 anticipated increases to gross Core Market Administration Expense for Terasen Gas would be offset by Energy Management Services (EMS) revenue. Terasen Gas agreed to this with the understanding that 2004 EMS net revenue was sufficient to cover these increased costs. As well, with the creation of a single department to manage the gas supply functions for all Terasen Gas gas utilities, a single budget was created, which are outlined in the table below.

		Budget
2004 Core Market Expenses by Utility		
TGI net Core Market Administration expense	$1,600,000	
TGVI Core Market Administration expense excluding SCADA	$385,762	
TGW	$24,100	
Total	$2,009,862	
Approved 2004 Net Core Market Administration Expense		$2,009,862
2004 Increases ($40,000 for labour inflation, $91,000 for software/hardware costs)		$131,000
2004 Gross Core Market Administration Expense		$2,140,982
Core Market EMS revenue recovery offset		($131,000)
2004 Net Core Market Administration Expense		$2,009,862

2005 Gas Supply Department Budget

The proposed 2005 Gas Supply gross Core Market Administration Expense was set using the 2004 Gas Supply gross budget of $2,140,982 as a base. The proposed 2005 gross budget is $2,435,982, representing an increase of $295,000. The explanation for the budget increase is explained in the table below.

	Variance from 2004	Budget	
2004 Gross Core Market Administration Expense		$2,140,982	
Labour Inflation	$50,000		3% - Required to attract and retain knowledgeable staff
Resource Planning Analyst	$100,000		See note 1 below
Legal	$100,000		See note 2 below
Other Costs	$45,000		See note 3 below
Total 2005 increases		295,000	
2005 Gross Core Market Administration Expense		$2,435,982	
Projected Core Market EMS revenue recovery offset	($70,000)	($70,000)	
2005 Net Core Market Administration Expense		$2,365,982	

Note 1: A resource analyst was hired in 2004, but 2004 costs were mitigated by early vacancies. The position's full year costs forms part of the 2005 base budget. This activity plays a key role in ensuring adequacy of supply, reliability of service (regional infrastructure capabilities, stress testing and peak day requirements) and assessment and mitigation of portfolio risk. As midstream manager, Terasen Gas plays a key role as customer steward, ensuring that British

Columbia's natural gas customers do not face a similar incident that the North East's electric customers did as a result of miss-managed infrastructure capacity/capabilities analysis. This also means an increased involvement in emergency planning.

Note 2: With the increased need for due diligence on contracts caused by evolving business rules (force majeure language, MI52-109, etc.), the increased number of counterparties and the negotiations required to come to agreement of contract terms, additional legal support is anticipated. A provision for up to $100K is included in the 2005 budget.

Note 3: The Northwest Gas Association (NWGA) is an organization of the Pacific Northwest natural gas industry. The NWGA's other members include the five natural gas utilities serving communities throughout Idaho, Oregon and Washington, and the three transmission pipelines that move natural gas from supply basins into and through the region. The member companies are Duke Energy, Gas Transmission Northwest, Williams Northwest Pipeline, Avista Energy, Cascade Natural Gas, Puget Sound Energy, Intermountain Gas and NW Natural. The organization is focused on facilitating company interactions in particular with respect to gas supply issues for the region and coordination with other regional entities such as the Northwest Power Planning Council. The NWGA publishes a Natural Gas Outlook annually and has helped Terasen Gas with research and preparation for input to the Terasen Gas Regional Resource Planning Study. Terasen Gas has negotiated a membership fee ($45,000) which is discounted from what other companies pay. This membership allows for Terasen Gas to be an active player in regional resource planning. It also allows the Northwestern Gas Utilities to form a joint force in negotiations with transportation companies. It is this type of cooperation that helped reduce an initial estimated $5 million increase in WEI tolls, requested in the 2004 WEI rate filing, down to $12,000.

For 2005 and beyond, Terasen Gas will continue to be allocated 80% of the Gas Supply net Core Market Administration Expense, TGVI – 19% and TGW – 1%. This is consistent with the allocation distribution of 2004 approved core market administration costs and is outlined in the table below.

	2005
TGI net Core Market Administration expense	$1,892,408
TGVI Core Market Administration expense excluding SCADA	$449,474
TGW	$24,100
Total Gas Supply net Core Market Administration expense	**$2,365,982**

Gas Supply EMS Revenue: Profit Sharing Methodology for 2005 and beyond

In 2003, when the BC Gas [now "Terasen Gas"] Gas Supply group first took on some activities for Centra Gas British Columbia [now "Terasen Gas (Vancouver Island) Inc.], it was done with the following objective: Optimize gas supply management costs for the two companies. The cost optimization comes directly from activity and technology synergies along with enhanced staff retention due to role and scope expansion.

With the success of this expansion, it was anticipated that the uniquely skilled Gas Supply staff could potentially provide these activities to third parties for profit, which would further enhance the objective. In 2004 the Terasen Gas identified and successfully realized on opportunities to market EMS outside the Terasen family of companies. Terasen Gas believes that it can continue to pursue and capture incremental net revenues from such services and that it should be encouraged to do so.

Terasen Gas believes that it is desirable that incentives be put in place to promote utility efficiencies, align customer and shareholder interests and to encourage management to take reasonable risk to control costs in both the long and short run. Customers achieve the benefit of reduced gas costs by:

a) Receiving a share of EMS net revenue which is applied to offset gross gas supply department costs.

b) Minimizing expense incurred to attract and train new personnel as turnover of skilled employees is reduced. Staff is incented to stay through job enrichment related to additional challenge in their work.

c) Increased efficiency of staff, since their skills are used to generate revenue.

d) Incenting the company (through sharing mechanism) to look for additional revenue generating opportunities.

In keeping with the incentive principles embedded in the PBR (i.e. that risks and rewards of efficiency gains are shared equally between customers and the Company) Terasen Gas proposes that net variances from the approved Core Market Administration Expense of $1,892,408 (as previously stated) be shared 50/50 with Customers and shareholders. This variance may come from a combination of factors including but not limited to savings from efficiencies and revenue generated in excess of expenses for service provided by EMS.

B. CUSTOMER ADVISORY COUNCIL MEETINGS

2004 Meetings

Established by the July Settlement Agreement, the Customer Advisory Council is a forum for customer groups and Terasen Gas to meet twice yearly for the purpose of communicating and resolving customers' concerns that may have arisen during the year. Both the May and October meetings were held were held at the Terasen Centre, 1111 West Georgia, Vancouver, BC.

The issues discussed at the May 7, 2004 meeting were as follow:

- Gas Supply Overview presented by Ed Small, CanAm Energy
- Customer Overview
- Unbundling Update
- Customer Initiatives Update
  - Vancouver Island LNG Storage Plant
- Utilities Strategy Project – Terasen Gas Inc. and Terasen Gas (Vancouver Island) integration
- Other Items

Records of the meeting were kept and questions that arose during the meeting were responded to in full at that time. Actions that came out of the meeting were:

1. Suggestion: Post the SQI results on the website so that customers can monitor how well the Company is doing related to these Service Quality Indicators

   Action: Terasen Gas now posts SQI results quarterly on the Terasen Gas Inc. website

2. The issues discussed at the October 7, 2004 meeting were as follows:

   - Update on SQIs and Customer Initiatives including:
     - Customer Complaints
     - Customer Satisfaction

- Rate Schedule 14 Update
- Regulatory Update
- New Opportunities
    - Triple Point Initiative
- Growth Strategies

Records of the meeting were recorded and questions that arose during the meeting were responded to in full at that time. Discussion at the meeting centered around:

- Added information that would be useful at the Annual Review related to key drivers and expectations on effects that the reduced use per account might have on rates in future.
- A desire for Terasen Gas to create some visibility around the customer satisfaction metrics related to industrial customers. Terasen Gas has surveyed industrial customers in the past using in-depth interviews. Compared to residential and commercial customers, the industrial customer base includes a relatively small population (729 customers, comprising 33% of total consumption) with varied interests and company or industry specific issues. Therefore, a quantitative survey approach is not very practical.
- Industrial customers also receive regular communications and service from dedicated account managers and Terasen Gas receives regular feedback through these relationships, as well as through the active involvement of the marketers who represent many of the industrial customers. In fact, an independent survey conducted in 2002 on behalf of Terasen Gas concluded that the majority of industrial customers place a higher significance on their relationships with marketers, with a large number relying on the marketers to manage the relationship with Terasen Gas, lacking the resources, time or knowledge to deal with issues directly.
- Terasen Gas relayed the intent to discontinue Rate Schedule 14 offerings for the 2005/06 gas year. The customer benefits associated with Rate Schedule 14 (other than non-exclusive supply) will continue to be provided through Rate Schedule 14A which Terasen Gas plans to continue providing as a tariffed rate offering.

- The Triple Point Project was brought forward as an information item. Triple Point is a new process that Terasen Gas will use to test high volume gas meters in accordance with expected new Measurement Canada regulations at an average cost that is significantly lower than the next best available alternative in North America. This cost advantage will allow Terasen Gas' Measurement Technologies group to lower costs to customers for testing of Terasen Gas' own high volume meters and by providing this service to third parties, opportunities will be created to reduce the overall cost of meter testing while not exposing Gas customers to market or financial risk for the first several years of operation. A regulatory construct for Triple Point is planned to be filed by end of November.
- Clear and consistent messaging and communication about decisions that could impact revenue requirements was reiterated by customer's as an important attribute to keep trust and goodwill between the customer and the Company. In future, when the Company makes Application to the Commission the customer groups are requesting to also be advised if there could be any implication arising from the Application which might impact revenue requirements and rates. By way of example, customers felt Terasen Gas should have advised customers in advance of the Company approaching the Commission to attempt to secure a regulatory calendar date for 2005 related to a request for a generic ROE review.

Terasen Gas also reviewed the challenges related to the economic drivers in the PBR as it relates to customer attachments, and highlighted that the multi-family housing market as the area the Company had targeted as having the best prospects for influencing positively our customer attachment objectives.

In keeping with the intent of the 2004 – 2007 PBR Settlement to keep customers informed and meeting twice yearly for the purposes of communicating and resolving customers' concerns that may have arisen during the year, Terasen Gas will continue to schedule such meetings for Spring and Fall of 2005.

<u>October 15, 2003 Meeting</u>

The following issues arose at the October 15, 2003 meeting in which Terasen Gas was unable to provide responses at the time. Terasen Gas now provides information to those issues below:

1) What is the ratio of lock-offs for residential versus commercial customers?

- On an annual basis 4.9% of all arrears disconnections relate to commercial customers. The balance 95.1% apply to residential customers. The table below indicates the number of customers in each rate class in comparison to the total customer base and the percentage of lock-offs associated with each rate class. (These statistics exclude Vancouver Island and Whistler.)

Customers			**Disconnection Rate as a percentage of all arrears disconnects.**
Residential	701,359	90.0%	95.1%
Commercial	76,830	9.9%	4.9%
Other (Industrial)	1,162	1%	0%
TOTAL	779,351	100.0%	100.0%

- With the initial rollout of commercial commodity unbundling the bad debt related to participating and non-participating customers remains with the Utility.

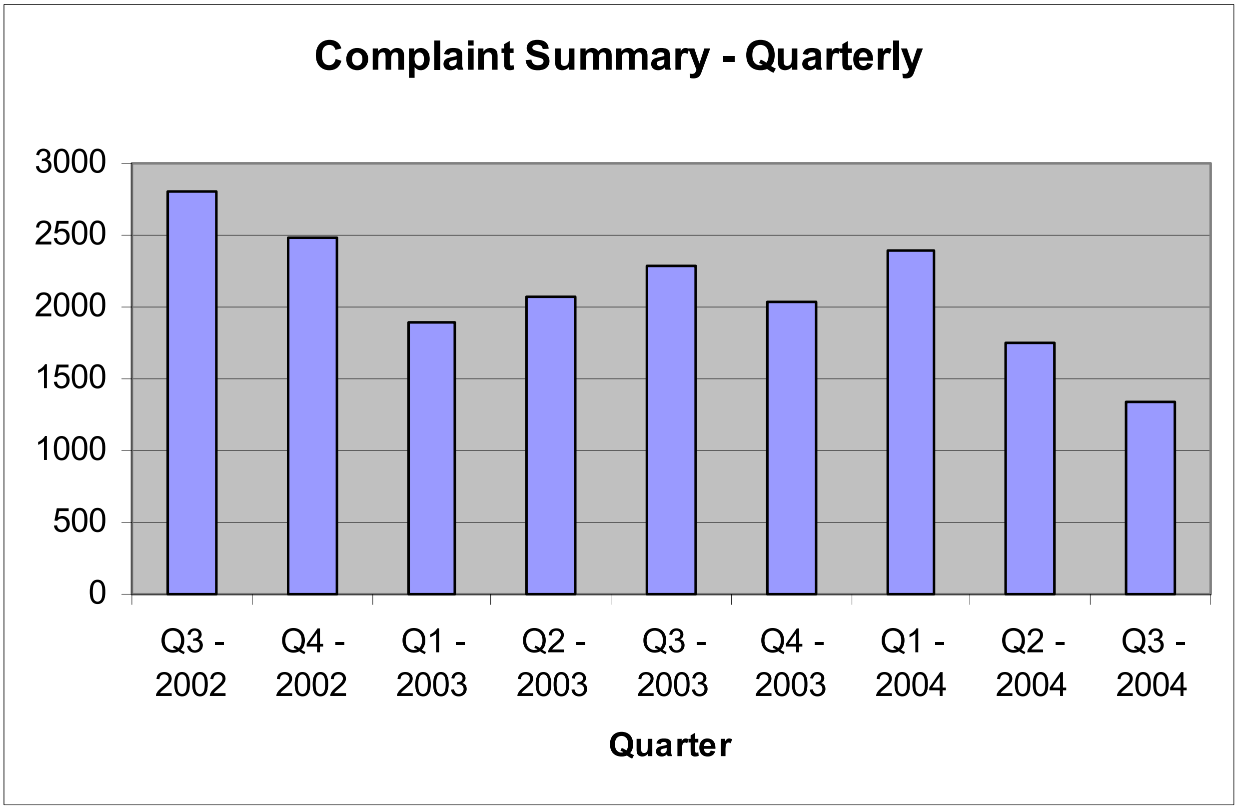
2) What is the number of security deposit requests that relate to brand new customers versus reconnect customers?

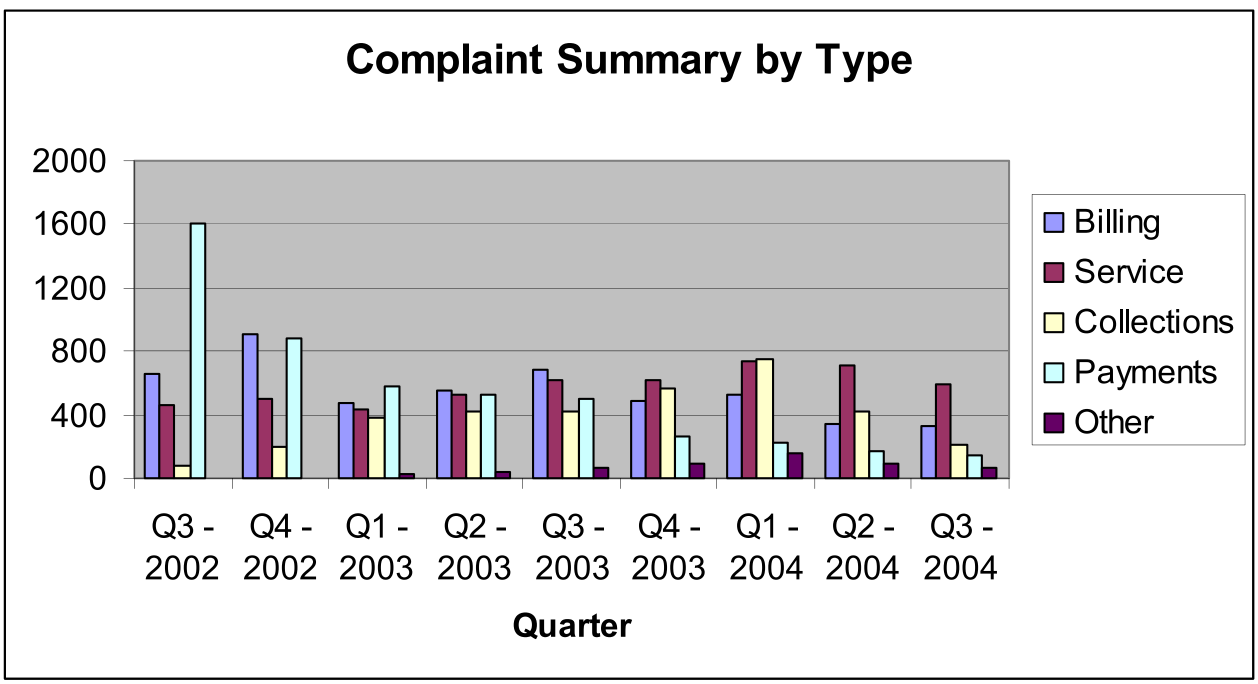
- Currently Terasen Gas does not track a reason associated with billing security deposits and are not able to obtain statistics related to the number of security deposits billed to new customers versus reconnecting customers. Based on the high level of disconnections processed over the last year which include a mandatory security deposit for reconnection, Terasen Gas believes the majority of deposits are associated with reconnecting customers.

- For residential customers that are new to the Company, Terasen Gas offers the alternative of authorizing a credit check through an external agency. The majority of customers authorize the request resulting in 63% of new applications being approved. In these cases a security deposit is not required. Terasen Gas does not require security from customers moving within our franchise area but will retain an existing deposit if the customer's payment history does not support a refund at that time. On an exception basis, the Company also will waive a security deposit if the customer participates in the preauthorized payment plan.
- Security deposits are required for all new commercial customers.

3) Report on the number and type of complaint calls to CustomerWorks related to Terasen Gas' services.

- The two graphs below reflect the total number of customer complaints by quarter logged with CustomerWorks since the repatriation of the lower mainland customers in July 2004. The first graph is a summary of all complaints by quarter and the second shows the breakdown by category.
- Overall Terasen Gas is seeing a decline in complaints over time. There is a definite seasonality to this activity however and the Company would expect the numbers to curve upward over the winter heating season particularly in the billing and collections areas.


Complaint Summary - Quarterly
3000
2500
2000
1500
1000
500
0
Q3 - 2002
Q4 - 2002
Q1 - 2003
Q2 - 2003
Q3 - 2003
Q4 - 2003
Q1 - 2004
Q2 - 2004
Q3 - 2004
Quarter


Complaint Summary by Type
2000
1600
1200
800
400
0
Q3 - 2002
Q4 - 2002
Q1 - 2003
Q2 - 2003
Q3 - 2003
Q4 - 2003
Q1 - 2004
Q2 - 2004
Q3 - 2004
Quarter
Billing
Service
Collections
Payments
Other

- <u>Billing</u>: This category includes complaints related to rates, payment plans, billing frequency and statement design and delivery.
- <u>Service</u>: The service category includes specific complaints related to call handling, meter reading, and customer service fieldwork.
- <u>Collections Complaints</u>: These include concerns relate to disconnection events, reconnection policy, security deposit requests and outbound collections calling.
- <u>Payments</u>: The majority of the complaints related to payments refer to the policy to not provide a “free” credit card payment service. As this service had previously been offered by BC Hydro the number of complaints was very high initially but has declined over time. Terasen Gas now offers a “user-pay” credit card service for those customers preferring this payment method.
- <u>Other</u>: The final category includes a small number of escalated complaints and unique concerns related to very specific situations that are not compatible with the Company’s standard reporting categories.

C. CUSTOMER GROWTH STRATEGY – NEW RESIDENTIAL MARKETS

Context

Terasen Gas recognizes that the ability to deliver cost-effective energy services to its customers over the long term requires a balance between operational excellence and a renewed focus on growth. As evidence of this, a corporate goal has now been set to have one million customers across all Terasen Gas service territories by the end of 2010.

Overview

Additional throughput mitigates rate pressures for existing customers; therefore, it is imperative that plans include retention and growth of existing customer loads as well as tactics to achieve capture rate targets for conversion loads and new construction.

In 2004, Terasen Gas' objective is to achieve net customer additions of at least 10,800 gross customer additions for the Terasen Gas service territory. Current projections indicate that we will likely exceed this target. Meeting that objective and positioning the Company for accelerated customer additions beyond 2004 will be achieved through the activities described in the following discussion.

The definition and prioritization of activities follows an assessment of the operating environment in which Terasen Gas operates. Some of the key issues that affect the Company are as follows:

- price competitiveness for gas versus other fuels has diminished
- housing construction activity is higher than in recent years and dwellings built are moving towards a higher proportion of multi-family units
- need to improve service delivery processes to improve builder/developer customer satisfaction

It should be noted that the Company's ability to meet the significant increases in customer attachments to meet its growth targets is dependent on a continuation of housing starts at current levels and no degradation of the competitive price of natural gas versus other fuels.

While Terasen Gas cannot influence housing starts, Terasen Gas can have an influence on gas price by employing hedging strategies to ensure natural gas remains competitive with alternative fuels (primarily electric). Terasen Gas also uses commodity hedging to dampen rate volatility and to reduce the risk of regional price disconnects. Finally, Terasen Gas has helped to minimize price increases through meeting productivity improvement targets and sharing these cost savings with our customers through PBR cost-sharing incentives.

Strategic Focus

Key areas of strategic focus to achieve higher growth in 2005 will be:

Multi Family dwellings (MFD)*:* Critical to meeting customer growth targets is the need to increase market share in the growing multi-family market, especially projects with individual metering potential. Market share of natural gas is low for a number of end-uses in MFD markets and is continuing to decline as a result of diminishing commodity price competitiveness relative to electricity. Electric baseboard is the prevalent method of suite heating in most applications, and anecdotal evidence suggests electric fireplaces have now displaced gas units in most projects. With the loss of the gas fireplace “anchor load” concern over continuing decline in other end-uses, such as ventilation and domestic water heating is warranted.

A key barrier to the implementation of natural gas in new MFD projects is the ability for the gas customer to individually meter their energy consumption. This ensures accountability for their energy consumption and helps to ensure appropriate price signals are sent to energy consumers. Terasen Gas will pursue growth in efficient energy utilization by end use and will also promote the individual metering concept.

Single family dwellings (SFD)*:* Marketing focus will be on retention of existing market share and to encourage modest growth rates where feasible. Large single-builder project will be the focus of renewed sales efforts in the SFD market.

Organizational capabilities: To achieve growth targets, Terasen Gas must ensure the required sales and marketing resources are in place and that the supporting delivery processes meet or exceed customer expectations. The following summarizes activities that are in process to ensure that Terasen Gas' organizational capabilities support achievement of customer growth targets.

- Add sales resources.
- Define desired sales process and supporting technology enhancements to existing business processes to enable effective, scalable handling of customer contacts.
- Enhance the service delivery process to provide a scalable business process from order initiation to closing to increase customer satisfaction by meeting customer expectations and thereby contributing towards achievement of long term growth goals.
- Promote efficient use of natural gas to ensure environmental stewardship, achieve customer satisfaction over the long term and maintain competitiveness relative to other energy sources.
- Complete an assessment of main extension and connection policies.

D. EXOGENOUS FACTORS

Terasen Gas is permitted to adjust the cost of service for “Exogenous Factors” pursuant to the provisions of the 2004-2007 Settlement Agreement (Appendix A, Page 14).

Terasen Gas has identified two items that merit exogenous treatment under the Judicial, legislative or administrative changes, orders and directions section of the Settlement Agreement.

1. Ontario Securities Commission Certification Compliance Costs

In response to high-profile financial scandals – most notably Enron and WorldCom, U.S. Congress passed a legislation known as the Sarbanes-Oxley Act (“SOX”) to protect investors and the general public from accounting errors and fraudulent practices in corporations. The act is administered by the Securities and Exchange Commission (SEC), which sets deadlines for compliance and publishes rules on requirements related to financial reporting and certification mandates.

Parallel to certification requirements of the SOX Act enacted in the United States in 2002, the Canadian Securities Administrators (the “CSA”) amended the Securities Act with Bill 198 in December 2002 and issued related Multilateral Instrument 52-109 – *Certification of Disclosure in Issuers’ Annual and Interim Filings* (“MI52-109”) in January 2004.

The purpose of MI52-109 is to improve the quality and reliability of reporting issuers’ annual and interim disclosures. The CSA believes that this, in turn, will help to maintain and enhance investor confidence in the integrity of Canadian capital markets.

Enforceable by the Ontario Securities Commission (“OSC”), MI52-109 is applicable for all OSC registrants effective March 30, 2004. Accordingly, transitional provisions require “bare” certification for interim and annual filings – including, but not limited to, financial statements and related note disclosure, the Annual Information Form, and the Management Discussion & Analysis – for fiscal periods ending before December 30, 2005, with “full” certification required thereafter.

As an OSC registrant and in accordance with MI52-109, Terasen Gas' first "bare" interim certification was required for the quarter ended March 31, 2004, with ongoing "bare" interim certifications required for interim periods throughout 2004 and 2005. "Bare" annual certification will be required for the year ended December 31, 2004. "Full" certification will be required for the year ended December 31, 2005 and for all reporting periods thereafter.

Terasen Gas estimates that its share of the total project costs associated with compliance of MI52-109 are $433,000 for calendar 2004 and $421,000 for calendar 2005. Certain of the shared costs of the project are incurred at Terasen Inc. and then cross-charged to Terasen Gas on a basis consistent with the Corporate Center cost allocations previously approved by the Commission. Accordingly, Terasen Gas proposes to defer the 2004 cost and amortize it fully in 2005. Terasen Gas also proposes to defer the 2005 cost and amortize it fully in 2005.

Details behind the associated compliance costs are as follows:

Terasen Gas Inc. - OSC Compliance Costs

	Budget 2004	Budget 2005
External Fees - Deloitte		
Initial Bare Certification	$ 40,000	$ -
Scoping, Planning, Disclosure Processes	132,850	-
Financial Reporting Processes	142,850	184,000
Admin Fee (5%)	16,223	-
External Fees - KPMG		
Project Steering Committee	12,500	12,500
Incremental Internal Costs		
Resourcing	49,073	212,000
Technology	9,379	-
Other	4,550	-
Contingency	25,404	12,500
Total	$ 432,828	$ 421,000

2. BCUC Levies

Actual 2004 BCUC levies have exceeded the amount provided for in 2004 rates as calculated in accordance with the O&M formula by $196,000. As these are imposed on Terasen Gas by outside authorities over which the Company has little or no control, Terasen Gas proposes to defer this amount in 2004 and amortize it fully as a cost of service item in 2005.

BCUC levies embedded in 2003 Decision	*$1,345,000*
2004 levies as calculated with O&M formula	*$1,369,000*
2004 projected BCUC Levies	*1,565,000*
Amount to defer	*$196,000*