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March 5, 2009

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. – Lower Mainland, Inland, and Columbia Service Areas Commodity Cost Reconciliation Account ("CCRA") and Midstream Cost Reconciliation Account ("MCRA") Quarterly Gas Costs 2009 First Quarter Report

The attached materials provide the Terasen Gas Inc. ("Terasen Gas" or the "Company") 2009 First Quarter Gas Cost Report for the CCRA and MCRA deferral accounts as required under British Columbia Utilities Commission (the "Commission") guidelines. In addition, the Company submits a correction to the Revenue Deficiency overstatement in the Amended Application of the Terasen Gas 2008 Annual Review of 2009 Revenue Requirements and Rates (the "Amended Application").

CCRA and MCRA Deferral Accounts

The CCRA balance at March 31, 2009, based on the February 24, 2009 forward prices, is projected to be approximately \$25 million surplus (after tax). Further, based on the February 24, 2009 forward prices, the gas purchase cost assumptions, and the forecast commodity cost recoveries at present rates for the 12-month period ending March 31, 2010, and accounting for the projected March 31, 2009 deferral balance, the CCRA ratio is calculated to be 126.4% (Tab 1, Page 1, Column 10, Lines 36/37). The ratio does not fall inside the deadband range of 95% to 105%, indicating that a rate change is required at this time.

Tab 2 provides the information related to the allocation of the forecast CCRA and MCRA gas supply costs based on the February 24, 2009 forward prices to the Sales Rate Classes. The schedules within this section indicate a decrease would be required to the Cost of Gas (Commodity Cost Recovery Charge), effective April 1, 2009, to eliminate the forecast over-recovery of the 12-month forward gas purchase costs and to amortize the projected March 31, 2009 surplus deferral balance. The revised rates, based on the flow-through calculation, for the Sales Rate Classes within the Lower Mainland, Inland, and Columbia Service Areas are shown in Tab 2, Table A, Page 1, Line 32. The Cost of Gas (Commodity Cost Recovery Charge) rate would decrease by \$1.574/GJ, from \$7.536/GJ to \$5.962/GJ, effective April 1, 2009.



The monthly deferral account balances for the CCRA and for the MCRA are shown on the schedules provided within Tab 1, Pages 1 to 2, for the existing rates and within Tab 3, Page 1, for the proposed Cost of Gas (Commodity Cost Recovery Charge) effective April 1, 2009. Terasen Gas will continue to monitor and report MCRA balances consistent with the Company's position that midstream rates be reported on a quarterly basis and, under normal circumstances, midstream rates be adjusted on an annual basis with a January 1 effective date.

Delivery Rate Amendment

Commission Order No. G-191-08, dated December 11, 2008, approved the increased delivery charges for customers served under Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X, 4, 5, 6, 7, 22, 22A, 22B, 23, 25, and 27 effective January 1, 2009 as determined through the Terasen Gas 2008 Annual Review of the 2009 Revenue Requirements and Rates process and presented in the Amended Application filed by the Company on December 3, 2008.

On January 1, 2009, in accordance with Order No. G-191-08, the Company implemented the approved delivery rates. It has since come to the Company's attention that these delivery rates were overstated by approximately 1.26%, caused by a \$5.7 million understatement of the revenue at existing rates in the Amended Application and a corresponding overstatement of the resulting revenue deficiency.

Revenue Deficiency

The Company has corrected the understatement of revenue at existing rates and has recalculated the 2009 revenue deficiency. The revised 2009 revenue deficiency is \$29.4 million as compared to the deficiency of \$35.1 million as filed in the Amended Application on December 3, 2008. The 2009 revenue requirement and rate base were correctly calculated and are not impacted by this change.

The Company proposes that the delivery rates be recalculated on an annual basis to reflect the revised annual revenue deficiency of \$29.4 million. The Company also proposes that these new delivery rates go into effect April 1, 2009. The schedules attached in Tab 4, Pages 1 to 3, provide revised schedules for Section A-1, Page 5 as well as Section A-4, Pages 14 and 14.1 of the Amended Application.

2009 Delivery Rate Refund Rider

Due to limitations in the current customer billing system, for the period of time between January 1, 2009 and the implementation of the revised rates in the customer billing system on April 1, 2009, the Company proposes to calculate the amount of the variance between the current and revised rates, and return this difference to customers through a rate rider over the remainder of 2009. This method will achieve the result of returning the first quarter difference to customers in the most efficient manner possible. As the



existing Rate Rider 4 is set to expire March 31, 2009, the Company proposes to continue with Rate Rider 4 and update the associated rate to reflect the refund applicable to each rate schedule. The overstated revenue deficiency and calculation of the proposed Rate Rider by rate schedule can be found in Tab 4, Page 4.

In summary, Terasen Gas requests Commission approval of the following effective April 1, 2009:

- Approval to flow through a decrease of \$1.574/GJ to Commodity Cost Recovery Charges for Sales Rate Classes within the Lower Mainland, Inland and Columbia Service Areas, effective April 1, 2009, to a new rate of \$5.962/GJ.
- The Midstream Cost Recovery Charges remain unchanged.
- Revised delivery rates for customers served under Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X, 4, 5, 6, 7, 22, 22A, 22B, 23, 25 and 27 effective April 1, 2009, as set out in Tab 5.
- Revised Rate Rider 4 to be effective April 1, 2009 to December 31, 2009, as set out in Tab 4, Page 4.

The proposed aggregate rate changes would decrease Lower Mainland Rate Schedule 1 rates by \$1.643/GJ and result in a decrease to a typical Lower Mainland residential customer's annual bill, with an average annual consumption of 95 GJ, of approximately \$156 or 12.7%. Tabs 5 and 6 provide the aggregate rates changes in the tariff continuity and the bill impact schedules.

We trust that the Commission will find this filing in order. If there are any questions regarding this filing, please contact Brian Noel at 604-592-7467.

All of which is respectfully submitted.

Sincerely,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachments

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS CCRA MONTHLY BALANCES AT EXISTING RATES (AFTER VOLUME ADJUSTMENTS) AND RATE CHANGE TRIGGER MECHANISM FOR THE FORECAST PERIOD APRIL 1, 2009 TO MARCH 31, 2011 FEBRUARY 24, 2009 FORWARD PRICES

\$(Millions)

Line No.	(1)		(2)	(3)	(4)		(5)		(6)		(7)		(8)	(9)	(10)	(1	1)	(*	12)	(13)	(14)
1 2			orded :t-08		orded v-08	Recor Dec-		Recorde Jan-09		Projected Feb-09		ojected ar-09														
3	CCRA Balance - Beginning (Pre-tax) (1*)	\$	(50)	\$	(46)	\$	(40)	\$ (3	3) 3	\$ (29)	\$	(30)														
4	Gas Costs Incurred	\$	58	\$	64	\$	68	\$6	3 3	\$55	\$	57														
5	Revenue from EXISTING Recovery Rates	\$	(54)	\$	(58)	\$	(61)	\$ (6	i0)	\$ (56)	\$	(62)														
6	CCRA Balance - Ending (Pre-tax) ^(2*)	\$	(46)	\$	(40)	\$	(34)	\$ (2	9)	\$ (30)	\$	(36)														
7																										
8	CCRA Balance - Ending (After-tax) ^(3*)	\$	(32)	\$	(28)	\$	(23)	\$ (2	1)	\$ (21)	\$	(25)														
9 10																									т	otal
11																										r-09
12			ecast		ecast	Forec		Forecas		Forecast		recast		orecast		ecast		ecast	Fore			ecast		ecast		to
13		Ap	r-09		y-09	Jun-		Jul-09		Aug-09		ep-09		0ct-09		v-09		ec-09	Jan			b-10		ar-10		ir-10
14	CCRA Balance - Beginning (Pre-tax) ^(1*)	\$	(36)		(51)		(65)		9) 9			(106)		(119)		(131)		(134)		(132)		(132)		(132)		(36)
15	Gas Costs Incurred	\$	38	•	40		39		1 5				\$		\$	50			\$		\$		\$		\$	547
16	Revenue from EXISTING Recovery Rates	\$	(53)		(55)		(53)		5)			(53)		(55)		(53)		(55)		(55)		(50)		(55)		(647)
17	CCRA Balance - Ending (Pre-tax) ^(2*)	\$	(51)	\$	(65)	\$	(79)	\$ (9	3)	\$ (106)	\$	(119)	\$	(131)	\$	(134)	\$	(135)	\$	(132)	\$	(132)	\$	(132)	\$	(132)
18 19	CCRA Balance - Ending (After-tax) ^(3*)	\$	(35)	¢	(46)	¢	(55)	¢ (6	5)	\$ (74)	¢	(83)	¢	(92)	¢	(94)	¢	(95)	¢	(94)	¢	(94)	¢	(95)	¢	(95)
20	Conta Balance Ending (Anch lax)	Ψ	(55)	Ψ	(40)	Ψ	(55)	ψ (0	5)	ψ (/+)	Ψ	(00)	Ψ	(32)	Ψ	(34)	Ψ	(33)	Ψ	(34)	Ψ	(34)	Ψ	(33)	Ψ	(33)
21																										otal
22				-		-		-		F	-		-				-						-			r-10
23 24			ecast r-10		ecast v-10	Forec		Forecas Jul-10	st	Forecast Aug-10		recast ep-10		orecast Oct-10		ecast v-10		ecast	Fore Jan			ecast b-11		ecast ar-11		to ır-11
25	CCRA Balance - Beginning (Pre-tax) (1*)	<u> </u>	(132)		(141)		149)		(7)	ě		(171)		(178)		(184)		(185)		(178)		(176)		(174)		(132)
26	Gas Costs Incurred	\$	43		45		44		6 5	,		45		47		51		55		` '	\$	· · /	\$. ,	\$	584
27	Revenue from EXISTING Recovery Rates	\$	(52)		(54)		(52)		(4)			(52)		(54)		(52)		(54)		(54)		(48)	•	(54)	•	(631)
28	CCRA Balance - Ending (Pre-tax) ^(2*)	\$	(141)		(149)		157)		(4)			(178)		(184)		(185)		(183)		(176)		(174)		(174)		(174)
29			. /		. /				,			. /		. ,		<u> </u>						× /				
30	CCRA Balance - Ending (After-tax) ^(3*)	\$	(101)	\$	(107)	\$ (112)	\$ (11	7)	\$ (122)	\$	(127)	\$	(132)	\$	(132)	\$	(131)	\$	(129)	\$	(128)	\$	(128)	\$	(128)
31																										
32 33																										
	CCRA RATE CHANGE TRIGGER MECHANISM																									
35																										
	CCRA = Forecast Recover									0000	_	= •	\$	647		=	12	6.4%								
37	Ratio Forecast Incurred Gas Costs (Apr 2009	- Mar 2	U10) +	Projec	cted CC	RA Pre	e-tax E	salance (war	2009)			\$	512		=										

Notes: Slight differences in totals due to rounding.

(1*) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts (Jan 1, 2008, 31.0%, Jan 1, 2009, 30.0%, Jan 1, 2010, 28.5%, and Jan 1, 2011, 26.5%).

(2*) For rate setting purpose CCRA pre tax balances include grossed up projected deferred interest as at March 31, 2009.

(3*) For rate setting purpose CCRA after tax balances are independently grossed-up to reflect pre-tax amounts.

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS MCRA MONTHLY BALANCES AT EXISTING RATES (AFTER VOLUME ADJUSTMENTS FOR THE FORECAST PERIOD APRIL 1, 2009 TO MARCH 31, 2011 FEBRUARY 24, 2009 FORWARD PRICES

\$(Millions)

Line No.	(1)		(2)	(3)		(4)	((5)	(6)		(7)		(8)		(9)	(10)	(11)		(12)		(13)	(14)
1 2																		Recorded Oct-08		ecorded		ecorded Dec-08	
3	MCRA Balance - Beginning (Pre-tax) (1*)																	\$ (7)\$	(22)\$	(9)	
4	Gas Costs Incurred																	\$ 58	\$	111	\$	118	
5	Revenue from EXISTING Recovery Rates																	\$ (72	2) \$	(99) \$	(144)	
6	MCRA Balance - Ending (Pre-tax) ^(2*)																-	\$ (22	2) \$	(9) \$	(34)	
7																							
8	MCRA Balance - Ending (After-tax)																:	\$ (15)\$	(6) \$	(24)	
9 10																							
11																							
12			orded	Project		Projected		ecast	Foreca		Forecas		Forecast		recast	Forec		Forecast		orecast		orecast	Total
13	(4*)		n-09	Feb-0		Mar-09		or-09	May-0		Jun-09		Jul-09	-	ug-09	Sep-		Oct-09		lov-09		Dec-09	2009
14	MCRA Balance - Beginning (Pre-tax) ^(1*)	\$	(34)		27)			(25)		20)		3)		\$	49	•		\$ 105		111	•	99 8	
15	Gas Costs Incurred	\$	122		73	• -	•	19	•	(1)		1))\$	(1)		0		\$		\$	53 \$	
16	Revenue from EXISTING Recovery Rates	\$	(115)	· · ·	70)	,	•	(14)	•	18		5		\$	31		25		5) \$) \$	(82) \$	
17 18	MCRA Balance - Ending (Pre-tax) ^(2*)	\$	(27)	\$ (24)	\$ (25)	\$	(20)	\$	(3)	\$ 2	20	\$ 49	\$	79	\$	105	\$ 111	\$	99	\$	70 \$	5 70
19	MCRA Balance - Ending (After-tax) ^(3*)	\$	(19)	\$ (17)	\$ (18)	\$	(14)	\$	(2)	\$ 1	4	\$ 34	\$	56	\$	73	\$ 77	′\$	69	\$	49	5 49
20		Ψ	(13)	Ψ (17)	φ (10)	Ψ	(14)	Ψ	(2)	ψι	Ŧ	ψυτ	Ψ	00	Ψ	10	ψ	Ψ	00	Ψ		р <u>н</u> ј
21																							
22		For	ecast	Foreca		Forecast	Far	ecast	Foreca		Forecas		Forecast	Га	recast	Forec		Forecast	г.	orecast	г.	orecast	Total
23 24			n-10	Foreca Feb-1		Mar-10		ecasi r-10	May-1		Jun-10		Jul-10		ug-10	Sep-		Oct-10		lov-10		Dec-10	2010
25	MCRA Balance - Beginning (Pre-tax) (1*)	\$			36			(5)		(5)			\$ 28		51		75		\$		\$	80 \$	
26	Gas Costs Incurred	\$	62	\$	51	\$ 40	\$	17		(3)		2))\$	(2)	\$	(7)	\$ 8	\$	67	\$	60 \$	5 288
27	Revenue from EXISTING Recovery Rates	\$	(95)	•	74)	•	•	(17)	•	17		, :1			26		22		s) \$)\$	(85)	
28	MCRA Balance - Ending (Pre-tax) ^(2*)	\$	36	. ,	12			(5)		9		8		\$	75		90		\$		\$	55	
29																							
30	MCRA Balance - Ending (After-tax) ^(3*)	\$	26	\$	9	\$ (3)	\$	(3)	\$	7	\$ 2	20	\$ 36	\$	53	\$	64	\$ 64	\$	57	\$	39 3	\$ 39

Notes: Slight differences in totals due to rounding.

(1*) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts (Jan 1, 2008, 31.0%, Jan 1, 2009, 30.0%, Jan 1, 2010, 28.5%).

(2*) For rate setting purpose MCRA pre tax balances include grossed up projected deferred interest as at March 31, 2009.

(3*) For rate setting purpose MCRA after tax balances are independently grossed-up to reflect pre-tax amounts.

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS SUMAS INDEX FORECAST FOR THE PERIOD ENDING MARCH 31, 2011 AND US DOLLAR EXCHANGE RATE FORECAST UPDATE

	AND US DOLLAR EXCH	ANGE RATE FOR	RECAST UPI	DATE		Feb 24, 2009 F	orwar	d Prices
Line		ov 24, 2008 Forwa		Feb 24, 2009 Forwa		Le	SS	
No		2008 Q4 Gas Cos	t Report	2009 Q1 Gas Cos	t Report	Nov 24, 2008 F		d Prices
	(1)	(2)		(3)		(4) = (3	i) - (2)	
1	Sumas Index Prices - \$US/MMBTU	Α.						
2	2008 July		11.69	\$	11.69		\$	-
3	August	\$	7.94	\$	7.94		\$	-
4 5	September October	Secondard \$	6.94 6.23	∧ \$ \$	6.94 6.23		\$ \$	-
5 6	November	Recorded \$ Projected \$	6.23 6.28	\$	6.23		э \$	-
7	December	Forecast \$	6.63	lj ⊅ Recorded \$	6.66		φ \$	0.03
8	Simple Average (Jan, 2008 - Dec, 2008)	\$	8.33	\$	8.33	0.0%	<u>.</u>	-
		<u>3</u> \$	8.02	<u>\$</u> \$	7.59	-5.4%	-	
9	Simple Average (Apr, 2008 - Mar, 2009)						<u> </u>	(0.43)
10	Simple Average (Jul, 2008 - Jun, 2009)	\$	7.11	\$	6.04	-15.0%	-	(1.07)
11	Simple Average (Oct, 2008 - Sep, 2009)	\$	6.54	\$	4.84	-26.0%	-	(1.70)
12	2009 January	Forecast \$	7.10	Recorded \$	6.89		\$	(0.21)
13	February		7.08	Projected \$	4.80		\$	(2.28)
14	March		6.63	Forecast \$	3.88		\$	(2.75)
15	April	∜ \$ \$	6.22	\$	3.63		\$ \$	(2.59)
16 17	May June	\$ \$	6.26 6.36	∥ \$ V \$	3.72 3.85		ծ \$	(2.54)
18	July	э \$	6.48	v 3 \$	3.65		э \$	(2.51) (2.49)
19	August	\$	6.58	\$	4.07		\$	(2.51)
20	September	\$	6.62	\$	4.11		\$	(2.52)
21	October	\$	6.71	\$	4.21		\$	(2.50)
22	November	\$	7.82	\$	4.88		\$	(2.94)
23	December	\$	8.19	\$	6.19		\$	(2.00)
24	Simple Average (Jan, 2009 - Dec, 2009)	\$	6.84	\$	4.52	-33.9%	\$	(2.32)
25	Simple Average (Apr, 2009 - Mar, 2010)	\$	7.20	\$	4.77	-33.8%	\$	(2.43)
26	Simple Average (Jul, 2009 - Jun, 2010)	\$	7.35	\$	5.11	-30.5%	\$	(2.24)
27	Simple Average (Oct, 2009 - Sep, 2010)	\$	7.48	\$	5.43	-27.4%	-	(2.05)
28	2010 January	\$	8.44	\$	6.46		\$	(1.97)
29	February	\$	8.44	\$	6.47		\$	(1.97)
30	March	\$	8.27	\$	5.60		\$	(2.67)
31	April	\$	6.87	\$	5.06		\$	(1.81)
32	May	\$	6.84	\$	5.09		\$	(1.75)
33	June	\$	6.93	\$	5.18		\$	(1.75)
34	July	\$	7.04	\$	5.30		\$	(1.74)
35 36	August	\$ \$	7.12 7.15	\$ \$	5.38 5.41		\$ \$	(1.74)
30 37	September October	э \$	7.13	\$ \$	5.50		э \$	(1.74) (1.72)
38	November	\$	8.27	\$ \$	6.06		φ \$	(2.21)
39	December	\$	8.59	\$	7.19		\$	(1.40)
40	Simple Average (Jan, 2010 - Dec, 2010)	\$	7.60	\$	5.72	-24.7%	<u> </u>	(1.88)
41	Simple Average (Apr, 2010 - Mar, 2011)			\$	5.95		-	
42	2011 January			\$	7.41			
43	February			\$	7.42			
44	March			\$	6.46			
45								
46		recast Jan 2009-E	Dec 2009	Forecast Apr 2009-N	1ar 2010			
47	GJ/MMBTU	1.055056	4 00 10	1.055056	4 0 4 0 0	0.001	¢	0.000
48	Average Barclays Bank Exchange Rate (\$1 US = \$x.xxxx CDN Bank of Canada Daily Exchange Rate (\$1 US = \$x.xxxx CDN)) \$	1.2312	\$	1.2406	0.8%	Ф	0.009
49 50	November 24, 2008 vs February 24, 2009	\$	1.2250	\$	1.2470	1.8%	\$	0.022
		•		·				

Tab 1

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS AECO INDEX FORECAST FOR THE PERIOD ENDING MARCH 31, 2011

Page 4

Line No	Particulars	Nov 24, 2008 Fo 2008 Q4 Gas (rward Prices	Feb 24, 2009 F 2009 Q1 Gas			Feb 24, 2009 F Le: Nov 24, 2008 F	SS	
<u></u>	(1)		2)		(3)		(4) = (3		
1	AECO Index Prices - \$CDN/GJ								
2	2008 July	Δ	\$ 10.80		\$	10.80		\$	-
3	August		\$ 8.44	٨	\$	8.44		\$	-
4	September		\$ 7.05	Ĥ	\$	7.05		\$	-
5	October	Recorded	\$ 5.91		\$	5.91		\$	-
6	November	Projected	\$ 6.56	U	\$	6.56		\$	-
7	December	Forecast	\$ 6.87	Recorded	\$	6.83		\$	(0.04)
8	Simple Average (Jan, 2008 - Dec, 2008)		\$ 7.71		\$	7.70	-0.1%	\$	(0.01)
9	Simple Average (Apr, 2008 - Mar, 2009)		\$ 7.86		\$	7.36	-6.4%	\$	(0.50)
10	Simple Average (Jul, 2008 - Jun, 2009)		\$ 7.44		\$	6.21	-16.5%	\$	(1.23)
11	Simple Average (Oct, 2008 - Sep, 2009)		\$ 7.13		\$	5.19	-27.2%	\$	(1.94)
12	2009 January	Forecast	\$ 7.37	Recorded	\$	6.22		\$	(1.15)
13	February	Π	\$ 7.39	Projected	\$	5.33		\$	(2.06)
14	March		\$ 7.35	Forecast	\$	4.59		\$	(2.76)
15	April		\$ 7.14	Π	\$	4.16		\$	(2.97)
16	May		\$ 7.17		\$	4.26		\$	(2.90)
17	June		\$ 7.28	Å	\$	4.42		\$	(2.87)
18	July		\$ 7.42		\$	4.58		\$	(2.84)
19 20	August September		\$7.53 \$7.59		\$ \$	4.67 4.71		\$ \$	(2.87) (2.87)
20	October		\$7.69		э \$	4.71		э \$	(2.87)
22	November		\$ 8.06		\$	5.39		\$	(2.67)
23	December		\$ 8.49		\$	6.06		\$	(2.43)
24	Simple Average (Jan, 2009 - Dec, 2009)		\$ 7.54		\$	4.93	-34.6%	-	(2.61)
25	Simple Average (Apr, 2009 - Mar, 2010)		\$ 7.87		\$	5.17	-34.3%	-	(2.70)
26	Simple Average (Jul, 2009 - Jun, 2010)		\$ 8.04		\$	5.57	-30.7%	-	(2.47)
27	Simple Average (Oct, 2009 - Sep, 2010)		\$ 8.20		\$	5.95		\$	(2.25)
28	2010 January		\$ 8.77		<u>\$</u>	6.37	27.170	<u>\$</u>	(2.40)
29	February		\$ 8.78		\$	6.37		\$	(2.40)
30	March		\$ 8.58		\$	6.23		\$	(2.35)
31	April		\$ 7.85		\$	5.82		\$	(2.04)
32	May		\$ 7.82		\$	5.85		\$	(1.97)
33	June		\$ 7.93		\$	5.96		\$	(1.97)
34	July		\$ 8.05		\$	6.10		\$	(1.96)
35	August		\$ 8.14		\$	6.19		\$	(1.95)
36	September		\$ 8.18		\$	6.23		\$	(1.95)
37	October		\$ 8.27		\$	6.34		\$	(1.93)
38	November		\$ 8.60		\$	6.74		\$	(1.86)
39	December		<u>\$ 8.97</u>		\$	7.19	o. 4. oo 4	\$	(1.78)
40	Simple Average (Jan, 2010 - Dec, 2010)		<u>\$ 8.33</u>		<u>\$</u>	6.28	-24.6%	\$	(2.05)
41	Simple Average (Apr, 2010 - Mar, 2011)				\$	6.54			
42	2011 January				\$	7.45			
43	February				\$ \$	7.44			
44	March				Φ	7.20			

Tab 1

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS STATION NO. 2 INDEX FORECAST FOR THE PERIOD ENDING MARCH 31, 2011

Page 5

Line	STATION NO. 2 INDEX F	Nov 24, 2008 F			Feb 24, 2009 F	orwar	d Prices	Feb 24, 2009 F Le		d Prices
No	Particulars	2008 Q4 Gas	Cost	Report	2009 Q1 Gas	Cost	Report	Nov 24, 2008 F	orwar	d Prices
	(1)		(2)			(3)		(4) = (3) - (2)	
1	Station No. 2 Index Prices - \$CDN/GJ									
2	2008 July	Ą	\$	10.59		\$	10.59		\$	-
3	August		\$	7.25	٨	\$	7.25		\$	-
4	September	U	\$	6.48	Ìľ	\$	6.48		\$	-
5	October	Recorded	\$	5.58		\$	5.58		\$	-
6	November	Projected	\$	6.84	U	\$	6.84		\$	-
7	December	Forecast	\$	6.97	Recorded	\$	7.15		\$	0.18
8	Simple Average (Jan, 2008 - Dec, 2008)		\$	7.68		\$	7.70	0.3%	-	0.02
9	Simple Average (Apr, 2008 - Mar, 2009)		\$	7.77		\$	7.21	-7.2%	\$	(0.56)
10	Simple Average (Jul, 2008 - Jun, 2009)		\$	7.25		\$	5.96	-17.8%	\$	(1.29)
11	Simple Average (Oct, 2008 - Sep, 2009)		\$	7.06		\$	5.05	-28.5%	\$	(2.01)
12	2009 January	Forecast	\$	7.52	Recorded	\$	6.52		\$	(0.99)
13	February	Π	\$	7.46	Projected	\$	4.79		\$	(2.67)
14	March		\$	7.23	Forecast	\$	4.05		\$	(3.18)
15	April	Ϋ	\$	6.98	Π	\$	3.97		\$	(3.00)
16	Мау		\$	7.01		\$	4.07		\$	(2.93)
17	June		\$	7.12	Ŷ	\$	4.23		\$	(2.90)
18	July		\$	7.26		\$	4.39		\$	(2.87)
19	August		\$	7.37		\$	4.48		\$	(2.90)
20	September		\$	7.43		\$	4.52		\$	(2.90)
21	October		\$	7.53		\$	4.64		\$	(2.89)
22	November		\$	8.20		\$	5.40		\$	(2.80)
23	December		\$	8.63		\$	6.06		\$	(2.57)
24	Simple Average (Jan, 2009 - Dec, 2009)		\$	7.48		\$	4.76	-36.4%	-	(2.72)
25	Simple Average (Apr, 2009 - Mar, 2010)		\$	7.84		\$	5.06	-35.5%	-	(2.78)
26	Simple Average (Jul, 2009 - Jun, 2010)		\$	8.01		\$	5.45	-32.0%	\$	(2.56)
27	Simple Average (Oct, 2009 - Sep, 2010)		\$	8.17		\$	5.83	-28.6%	\$	(2.34)
28	2010 January		\$	8.91		\$	6.38		\$	(2.54)
29	February		\$	8.92		\$	6.37		\$	(2.54)
30	March		\$	8.72		\$	6.23		\$	(2.48)
31	April		\$	7.70		\$	5.60		\$	(2.11)
32	Мау		\$	7.67		\$	5.63		\$	(2.04)
33	June		\$	7.78		\$	5.74		\$	(2.04)
34	July		\$	7.90		\$	5.88		\$	(2.03)
35	August		\$	8.00		\$	5.97		\$	(2.02)
36	September		\$	8.03		\$	6.01		\$	(2.02)
37	October		\$	8.12		\$	6.12		\$	(2.00)
38 39	November December		\$	8.74		\$ \$	6.75		\$ \$	(1.99)
			\$	9.11		<u> </u>	7.20	05.00/	<u> </u>	(1.91)
40	Simple Average (Jan, 2010 - Dec, 2010)		\$	8.30		<u>\$</u>	6.16	-25.8%	<u>⊅</u>	(2.14)
41	Simple Average (Apr, 2010 - Mar, 2011)					\$	6.42			
42	2011 January					\$	7.46			
43	February					\$	7.45			
44	March					\$	7.21			

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS

GAS BUDGET COST SUMMARY

Tab 1 Page 6

FOR THE FORECAST PERIOD APRIL 1, 2009 TO MARCH 31, 2010

FEBRUARY 24, 2009 FORWARD PRICES

Line Patious Code (500) Unit Code (500) Unit Code (500) Unit Code (500) Comments 1 Contact (10) (10) (10) (10) (10) 2 TOTAL (10) (10) (10) (10) (10) 2 TOTAL (10) (10) (10) (10) (10) 3 (10) (10) (10) (10) (10) 4 (10) (10) (10) (10) (10) 4 (10) (10) (10) (10) (10) 4 (10) (10) (10) (10) (10) 4 (10) (10) (10) (10) (10) 4 (10) (10) (10) (10) (10) 4 (10) (10) (10) (10) (10) 4 (10) (10) (10) (10) (10) 4 (10) (10) (10) (10) (10) 5				24,	2009 FORWA	KD FRICES	
No. Particularies (T) (8 00) (800) (800) Comments 1 CCRA (2) (3) (4) (5) (5) 3 Main eg 20.989.8 5.160 5.161 (5) (6)				1			
(1) (2) (3) (4) (6) 2 TERP PURCHASES 200,0 5 <td< th=""><th>Line</th><th></th><th>Volumes</th><th> </th><th>Costs</th><th>Unit Cost</th><th></th></td<>	Line		Volumes		Costs	Unit Cost	
(1) (2) (3) (4) (6) 2 TERM FUNCASES Anum 5 Anum 5 Anum 5 Allow 5 Allow	No.	Particulars	(TJ)	1	(\$ 000)	(\$/GJ)	Comments
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2 TEAP PURCHASES 0.0 \$ 0.0 \$ 0.0 \$ 0.00 \$ 5 140 4 Statum 22 20.096 \$ \$ 5 5 140 7 SEASONA 22.7893 \$ \$ 17702 \$ 5 140 8 Hunt 22.8805 \$ \$ 5 4.48 6.825 1 TOTAL SEASONAL 22.8805 \$ 5.448 5.885 1 TOTAL SEASONAL PURCHASES 22.0813 \$ 5.885 5.449 1 Station n2 73.504 \$ 5.885 5.885 14 Station n2 170.22.87 \$ 5.971 \$ 4.5316 14 Station n2 1.349 \$ 6.376 Fuel+n-Hind gas costs induited in CCRA commodity purchase costs 14 TOTAL CCRA - ADMINETABLE GAS \$ 5.871.9 \$ 5.476 12 TOTAL MCRA COMMODITY 27.786.4 \$ 5.376 <	1	.,	(-/		(0)	(.)	(8)
a Junt 0.00 \$ 5 - Station 22 20986.5 17403 5.146 4 5.137 5.146 5 17704 5.146 6 17403 5.146 7 5.146 5.177 6 17704 5.146 7 5.146 5.147 8 5.147 5.148 9 5.147 5.148 9 5.147 5.449 9 5.147 5.449 9 5.147 5.449 10 5.017 5.433 11 7.771 5.5478 12 5.207 22.20613 5.2786 12 5.2781 5.5371 5.5471 12 5.2781 5.5278 5.5278 12 7074.0000000000000000000000000000000000							
4 30000 42 AECO 7014, TERM PURCHASES 227303 247064 5.173 5.000 5 5 5.173 5.000 5.173 5.000 5.173 5.000 6 TOTAL, TERM PURCHASES 227303 5.000 5.446 5.000 5.446 5.000 7 TOTAL SEASONAL PURCHASES 41.070.7 5.000 5.466 5.000 5.467 5.000 10 AECO 5.000 5.468 5.000 5.467 5.000 11 TOTAL SEASONAL PURCHASES 41.070.7 5.000 5.585 5.000 5.420 5.000 11 Station #2 TOTAL CEA COMMODITY 8.5871.9 8.66188 5.5275 6.000 5.4300 12 FOTAL CEA ADMINISTRATION COSTS 1.346 665 FoleIn-Hind gas costs incluided in CCRA commodity purchase costs incluides incluided in CCRA commodity purchase costs incluides incluides incluided in CCRA commodity purchase costs incluides incluides incluided in CCRA commodity purchase costs incluides incluides inclui						<u>_</u>	
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7 Section A: Billion A: ACCO 12,880.3 ACCO 5,701,71 3,4333 5,644 6,002 4,502	5	AECO	1,740.3		9,003	5.173	
8 Hunt 12.880.8 \$ 70.171 \$ 4.44 9 Station #2 22.085.5 6.014 5.642 10 AECO 5.014 5.642 5.642 11 Station #2 5.033.0 22.085.5 4.313 12 Station #2 5.033.0 22.085.5 4.310 12 Fort AL SPOT PURCHASES 5.033.0 22.085.5 4.310 12 TOTAL CRA COMMODITY 65.871.9 \$ 4.5196.5 5.276 13 Batton #2 5.037.0 \$ 5.47.480 \$ 6.376 12 TOTAL CRA - COMMODITY 65.871.9 \$ 5.47.480 \$ 6.376 12 TOTAL MCRA COMMODITY 27.7864 \$ 135.501 \$ 4.876 13 TOTAL MCRA COMMODITY 27.7864 \$ 6.376 Fuel=n-kind gas coats included in CCRA commodity purchase costs 14 MCRA COMMODITY 27.7864 \$ 135.501 \$ 4.876 15 WorkMG 37.28 \$ 2.460 \$ 6.598 1004.00017 27.7864 \$ 135.501 \$ 10	6	TOTAL TERM PURCHASES	22,739.9	\$	117,066	\$ 5.148	
8 Hunt 12.880.8 \$ 70.171 \$ 4.44 9 Station #2 22.085.5 6.014 5.642 10 AECO 5.014 5.642 5.642 11 Station #2 5.033.0 22.085.5 4.313 12 Station #2 5.033.0 22.085.5 4.310 12 Fort AL SPOT PURCHASES 5.033.0 22.085.5 4.310 12 TOTAL CRA COMMODITY 65.871.9 \$ 4.5196.5 5.276 13 Batton #2 5.037.0 \$ 5.47.480 \$ 6.376 12 TOTAL CRA - COMMODITY 65.871.9 \$ 5.47.480 \$ 6.376 12 TOTAL MCRA COMMODITY 27.7864 \$ 135.501 \$ 4.876 13 TOTAL MCRA COMMODITY 27.7864 \$ 6.376 Fuel=n-kind gas coats included in CCRA commodity purchase costs 14 MCRA COMMODITY 27.7864 \$ 135.501 \$ 4.876 15 WorkMG 37.28 \$ 2.460 \$ 6.598 1004.00017 27.7864 \$ 135.501 \$ 10	7	SEASONAL					
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TOTAL SEASONAL PURCHASES 41.07.07 \$ 239.441 \$ 5.642 Sector Stations \$ - 73.504 4.318 Is Mark Stations \$ - 73.504 4.318 Is Acco 5.039.0 22.068.1 4.302 It Claim Canay, DOS 5.039.0 5.22.68 4.302 It Claim Canay, DOS 5.341 5.52.78 9.3018 It Claim Canay, DOS 5.341 5.547.480 5.63.76 It Claim Canay, DOS 5.341 5.547.480 5.63.76 It Claim Canay, DOS 3.3618 5.43.76 Fuelin-kind gas volumes are not part of total marketable gas It Claim Canay, DOS 3.78.8 5.135.01 5.43.76 Fuelin-kind gas volumes are not part of total marketable gas It MCRA 3.122.03 5.68.707 S.68.170 S.68.170 It Market AB 3.122.033 5.5140 <							
12 SOT Mult - 17,022.3 5 5 - 17,5504 5 - 17,5504 14 Station n2 5,030.0 5 4,318 15 AECO 22,081.3 5 4,318 16 TOTAL CRA COMMODITY 85,871.9 5 4,318 17 TOTAL CCRA ADMINISTRATION COSTS 20 CCRA ADMINISTRATION COSTS 1,348 20 CCRA ADMINISTRATION COSTS 1,348 5 547,480 5 658 21 TOTAL CCRA - MARKETABLE GAS 85,871.9 5 547,480 5 6,526 22 TOTAL CCRA - MARKETABLE GAS 85,871.9 5 4,876 5 6,527 24 MCRA 3 372.8 5 2,460 5 6,528 Daily priced - forecast at 1.5 x month price 23 TOTAL TRANSPORTATION \$ 8,51.40 5 6,5271 5 5.114 includes LNG 33 TOTAL TRANSPORTATION \$ 8,51.40 5 6.167 5 6.167 5 <td></td> <td></td> <td></td> <td>-</td> <td></td> <td></td> <td></td>				-			
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14 Station #2 17,022.3 73,504 4.318 ALCO TOTAL SPOT PURCHASES 5,039,0 2,268.13 5,039,0 4,309 18 TOTAL CCRA COMMODITY 85,871.9 \$ 453,196 \$ 5,278 Fuel-in-kind gas costs included in CCRA commodity purchase costs 19 TOTAL CCRA - MARKETABLE GAS 85,871.9 \$ 547,480 \$ 66.376 Fuel-in-kind gas costs included in CCRA commodity purchase costs 20 CCRA ADMINISTRATION COSTS 1,348 \$ 66.376 Fuel-in-kind gas costs included in CCRA commodity purchase costs 21 TOTAL CCRA - MARKETABLE GAS 85,871.9 \$ 4.675 Fuel-in-kind gas costs included in CCRA commodity purchase costs 22 TOTAL CCRA - MARKETABLE GAS 85,871.9 \$ 4.675 Fuel-in-kind gas costs included in CCRA commodity purchase costs 23 TOTAL CRA - MARKETABLE GAS 85,871.9 \$ 4.675 Fuel-in-kind gas costs includes in CCRA commodity purchase costs 24 MCRA COMMODITY 27,788.4 \$ 135,501 \$ 4.675 25 TOTAL TRANSPORTATION \$ 56,140 \$ 66,377 36 TOTAL TRANSPORTATION \$ 66,371 \$ 5,114 37 TOTAL TRANSPORTATION \$ 66	12	<u>SPOT</u>					
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Image: Constraint of Carbon Difference of Carbon	14	Station #2	17,022.3		73,504	4.318	
Image: Constraint of Carbon Difference of Carbon	15	AECO	5.039.0		22,685	4.502	
17 TOTAL CCRA COMMODITY 85,871.9 \$ 453,196 \$ 5.278 19 HEDGING (GAIN/LOSS) 1,348 5.278 20 CCRA ADMINISTRATION COSTS 1,348 5.278 21 FUEL-IN-KIND VOLUMES 1,348 5.371.9 5.47,480 \$ 6.376 21 FUEL-IN-KIND VOLUMES 1,348 5.47,480 \$ 6.376 Fuel-In-Kind gas costs included in CCRA commodity purchase costs 22 TOTAL CCRA - MARKETABLE GAS 85,871.9 \$ 547,480 \$ 6.376 Fuel-In-Kind gas volumes are not part of total marketable gas 24 MCRA OMMODITY 27.798.4 \$ 135,501 \$ 4.876 25 FUELINK-RO COMMODITY 27.798.4 \$ 6.598 Daily priced - forecast at 1.5 x month price 26 Includes IAR \$ 68,707 \$ 68,707 \$ 68,707 \$ 68,707 30 NVP TOTAL TRANSPORTATION \$ 68,707 \$ 68,707 \$ 68,707 30 S 020,600 \$ (18,903,2) \$ (17,718) 4,5147 Includes LNG 30 BC (Alkon) (28,901,8) \$ (194,929) <t< td=""><td></td><td></td><td></td><td>¢</td><td></td><td></td><td></td></t<>				¢			
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Image: state of the s			85,871.9	\$,	» 5.278	
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12 TOTAL CCRA MARKETABLE GAS MCRA 85.871.9 \$ 547,480 \$ 6.376 Fuel-in-kind gas volumes are not part of total marketable gas 23 MCRA COMMODITY TOTAL MCRA COMMODITY 27.788.4 \$ 135,501 \$.4.876 24 MCRA COMMODITY TOTAL MCRA COMMODITY 27.788.4 \$.0.536 Daily priced - forecast at 1.5 x month price 27 PEAKING 372.8 \$.0.971 \$.0.536 Daily priced - forecast at 1.5 x month price 28 TOTAL TRANSPORTATION \$.0.5371 \$.0.5371 \$.0.114 Fuel-in-kind gas volumes are not part of total marketable gas 29 WEI 372.8 \$.0.4870 \$.0.536 Daily priced - forecast at 1.5 x month price 38 TOTAL TRANSPORTATION \$.0.5371 \$.0.5371 \$.0.5371 \$.0.114 39 MIDAGAGE GAS (18,993.2) \$ (07.120) \$.0.114 \$.0.124 39 MIDAGAMAI (28.964.8) \$.0.2293 \$.0.4301 \$.0.4301 30 TOTAL IRANSPORTATION \$.0.293.3 \$.0.205 \$.0.4301 \$.0.4301 30 TOTAL IRANSPORTATION <td>20</td> <td>CCRA ADMINISTRATION COSTS</td> <td></td> <td></td> <td>665</td> <td></td> <td></td>	20	CCRA ADMINISTRATION COSTS			665		
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MCRA MCRA MCRA MCRA COMMODITY 23 TOTAL MCRA COMMODITY 27,788.4 \$ 135,501 \$ 4.876 26 FAKING 372.8 \$ 6.598 Daily priced - forecast at 1.5 x month price 27 PEAKING 372.8 \$ 6.598 Daily priced - forecast at 1.5 x month price 28 TRANSPORTATION \$ 68,797 9.971 - 20 VIEI \$ 68,797 9.971 - 21 TOTAL MANSPORTATION \$ 68,797 - - 31 NUP TOTAL INANSPORTATION \$ 68,773 - - 32 TOTAL INANSPORTATION (18,993.2) \$ (97,129) \$ 5.114 - 36 Alberta (Carbon) (2,894.3) (14,3010) - - 37 TOTAL INJECTION 20,533.3 \$ 123,028 \$ 5.049 - 37 TOTAL INTHORAWAL 31,233.9 \$ 14,837 4.985 - 38 TOTAL INTHORAWAL 31,243.9 \$ 17,933 - -	22	TOTAL CCRA - MARKETABLE GAS		\$	547 480	\$ 6.376	
MCRA COMMODITY 27,788.4 \$ 135,501 \$ 4.876 PEAKING 372.8 \$ 2,460 \$ 6.598 Daily priced - forecast at 1.5 x month price WEI \$ 68,797 \$ 68,797 \$ 68,797 \$ 6.371 NWP \$ 68,797 \$ 6.371 \$ 6.371 NWP \$ 561,400 \$ 51,140 STORAGE GAS \$ 68,160 \$ 118,993,21 \$ 51,141 Indection (18,993,21) \$ 51,141 \$ 63,797 Downstream (JP/Mist) (18,993,21) \$ 51,140 \$ 63,797 TOTAL INJECTION (18,993,21) \$ 51,140 \$ 101,40048 LNG Mithdraval (18,993,21) \$ 51,141 Includes LNG Downstream (JP/Mist) (28,961,80) \$ 5,992 Includes LNG Mithdraval 20,533,3 \$ 123,026 \$ 5,992 Includes LNG Aberta (Carbon) 2,9703 7,7403 \$ 6,021 \$ 6,021 B C (Alken) S 7,7403 \$ 6,021 \$ 6,021 \$ 6,021 Mitigation of Assets S 7,7403 \$ 116,2265 \$ 6,021 </td <td></td> <td></td> <td>00,011.0</td> <td>Ψ</td> <td>041,400</td> <td>φ 0.010</td> <td>r der in kind gas volumes die not part of total marketable gas</td>			00,011.0	Ψ	041,400	φ 0.010	r der in kind gas volumes die not part of total marketable gas
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54 OTHER 55 COMPANY USE GAS 56 GSMIP 57 MCRA ADMINISTRATION COSTS 58 HEDGING (GAIN)/LOSS 59 TOTAL MCRA - CORE 60 Core Sales Volume 61 108,178.8	53	TOTAL MITIGATION		\$	(174,386)		
55 COMPANY USE GAS (174.6) \$ (705) \$ 4.036 Company Use, Heater Fuel, Compressor Fuel 56 GSMIP 1,000 1,551 - 57 MCRA ADMINISTRATION COSTS 1,551 - 58 HEDGING (GAIN)/LOSS 1,551 - 59 TOTAL MCRA - CORE \$ 123,115 \$ 1.138 60 Core Sales Volume 108,178.8 61 Total Core sales volume per Gas Sales Forecast							
56 GSMIP 1,000 57 MCRA ADMINISTRATION COSTS 1,551 58 HEDGING (GAIN)/LOSS 1,551 59 TOTAL MCRA - CORE \$ 123,115 60 Core Sales Volume 108,178.8 61 Total Core sales volume per Gas Sales Forecast			(174 6)	\$	(705)	\$ 4.036	Company Use Heater Fuel Compressor Fuel
57 MCRA ADMINISTRATION COSTS HEDGING (GAIN)/LOSS 1,551 59 TOTAL MCRA - CORE \$ 123,115 60 Core Sales Volume 108,178.8 61 Total Core sales volume per Gas Sales Forecast			(174.0)	ľ			
58 HEDGING (GAIN)/LOSS 59 TOTAL MCRA - CORE 60 Core Sales Volume 61 108,178.8 Total Core sales volume per Gas Sales Forecast				I			
59 TOTAL MCRA - CORE \$ 123,115 \$ 1.138 Average unit cost based on Core sales volume 60 Core Sales Volume 108,178.8 Total Core sales volume per Gas Sales Forecast 61 Total Core sales volume per Gas Sales Forecast				I	1,551		
60 Core Sales Volume 108,178.8 61 Total Core sales volume per Gas Sales Forecast				-	-	* · ·	4
61	59	TOTAL MCRA - CORE		\$	<u>123,11</u> 5	\$ 1.138	Average unit cost based on Core sales volume
61	60	Core Sales Volume	108,178.8				Total Core sales volume per Gas Sales Forecast
			.,	1			,
		TOTAL BUDGET		¢	670 594		
	02	TOTAL BUDGET		Ψ	010,394		

Tab 1 Page 7

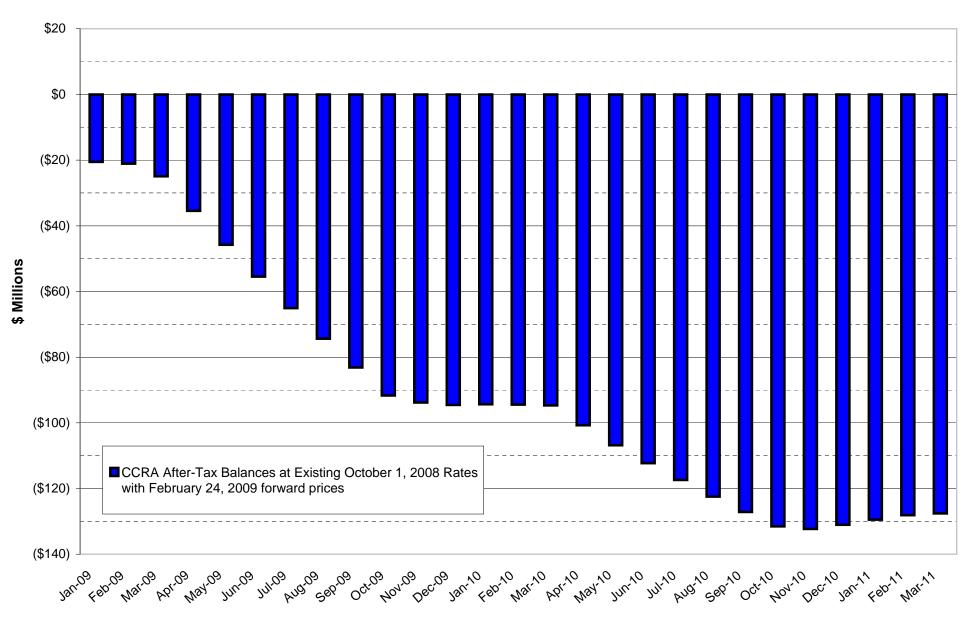
TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS RECONCILIATION OF GAS COST INCURRED FOR THE FORECAST PERIOD APRIL 1, 2009 TO MARCH 31, 2010 FEBRUARY 24, 2009 FORWARD PRICES \$(Millions)

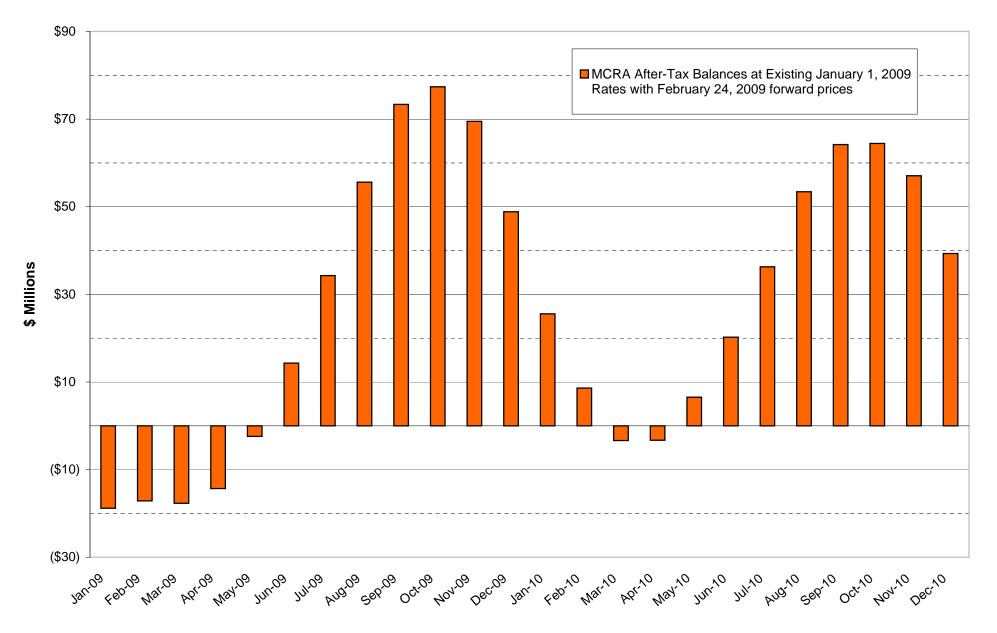
Line No.	Particulars	Deferra	A/MCRA Il Account recast	C	Budget Cost mmary
	(1)		(2)		(3)
1	Gas Cost Incurred				
2	CCRA (Tab 1, Page 1, Column 14, Line 15)	\$	547		
3	MCRA (Tab 1, Page 2, Col. 5 Line 15 to Col. 4, Line 26)		285		
4					
5					
6	Gas Budget Cost Summary				
7	CCRA (Tab 1, Page 6, Column 3, Line 22)			\$	547
8	MCRA (Tab 1, Page 6, Column 3, Line 59)				123
9	Total Net Costs for Firm Customers			\$	670
10					
11	Add back Off-System Sales				
12	Cost				152
13	Margin				5
14	-				
15	Add back On-System Sales				
16	Cost				5
17	Margin				-
18	J. J				
19					
20	Totals Reconciled	\$	832	\$	832

Note:

Slight differences in totals due to rounding

Terasen Gas Inc. Lower Mainland, Inland and Columbia CCRA After-Tax Monthly Balances Recorded to January 2009 and Projected to March 2011





Terasen Gas Inc. Lower Mainland, Inland and Columbia MCRA After-Tax Monthly Balances Recorded to January 2009 and Projected to Decmber 2010

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS COMMODITY COST RECONCILIATION ACCOUNT ("CCRA") Table A COST OF GAS (COMMODITY COST RECOVERY CHARGE) FLOW-THROUGH BY RATE SCHEDULE Page 1.0 FOR THE FORECAST PERIOD APRIL 1, 2009 TO MARCH 31, 2010

Tab 2

(FEBRUARY 24, 2009 FORWARD PRICING)

Line No.	Particulars	Unit		-1, RS-2, RS-3, S-5 and RS-6		RS-4		RS-7	I	RS-1 to RS-7 Total
<u>NO.</u>	(1)			(2)		(3)		(4)		(5)
1	CCRA Sales Volumes	TJ		85,646.8		213.1		12.1		85,871.9
2										
3										
4 5	CCRA Incurred Costs Station #2	\$000	\$	314,942.2	\$	878.0	\$	79.0	\$	315,899.2
6	AECO	\$000 \$000	Ψ	67,124.2	Ψ	1.2	Ψ	0.1	Ψ	67,125.5
7	Huntingdon	\$000		70,058.8		112.3		-		70,171.2
8	CCRA Commodity Costs before Hedging	\$000	\$	452,125.2	\$	991.6	\$	79.0	\$	453,195.9
9	Mark to Market Hedges Loss / (Gain)	\$000	\$	93,414.5		204.9		-	\$	93,619.4
10	Core Market Administration Costs	\$000	\$	663.3		1.5		-	\$	664.7
11 12	Total Incurred Costs before CCRA deferral amortization	\$000	\$	546,203.0	\$	1,197.9	\$	79.0	\$	547,479.9
13	Pre-tax Amortization CCRA Deficit/(Surplus) as of Apr 1, 2009	\$000	\$	(35,548.0)		(78.0)		-	\$	(35,626.0)
14	Total CCRA Incurred Costs	\$000	\$	510,655.0	\$	1,120.0	\$	79.0	\$	511,854.0
15										
16	CCRA Incurred Unit Costs									
17 18	CCRA Commodity Costs before Hedging	\$/GJ	\$	5.2790						
19	Mark to Market Hedges Loss / (Gain)	\$/GJ	Ψ \$	1.0907						
20	Core Market Administration Costs	\$/GJ	\$	0.0077						
21	CCRA Incurred Costs (excl. CCRA deferral amortization)	\$/GJ	\$	6.3774						
22	Pre-tax Amortization CCRA Deficit/(Surplus) as of Apr 1, 2009	\$/GJ	\$	(0.4151)						
23	CCRA Gas Costs Incurred Flow-Through	\$/GJ	\$	5.9623						
24										
25										
26 27								Fixed Price		
28						Tariff		Option		
29			RS	-1, RS-2, RS-3,		Equal To		Equal To		
30	Cost of Gas (Commodity Cost Recovery Charge		F	S-5 and RS-6		RS-5		RS-5		
31										
32	Proposed Flow-Through Cost of Gas effective Apr 1, 2009	\$/GJ	\$	5.962	\$	5.962	\$	5.962		
33	Evisting Orat of Ora (offertive since Ort 4, 0000)	¢/0 I	¢	7 500	۴	7 500	¢	7 500		
34 35	Existing Cost of Gas (effective since Oct 1, 2008)	\$/GJ	\$	7.536	\$	7.536	\$	7.536		
36	Cost of Gas Increase / (Decrease)	\$/GJ	\$	(1.574)	\$	(1.574)	\$	(1.574)		
37 38	Cost of Gas Percentage Increase / (Decrease)			-20.89%		-20.89%		-20.89%		

TERASEN GAS INC. - LOWER MAINLAND SERVICE AREA AND SUMMARY MIDSTREAM COST RECONCILIATION ACCOUNT ("MCRA") MIDSTREAM COST RECOVERY CHARGE FLOW-THROUGH BY RATE SCHEDULE FOR THE FORECAST PERIOD APRIL 1, 2009 to MARCH 31,2010 (FEBRUARY 24, 2009 FORWARD PRICING)

Line No.	Particulars (1)	Residential RS-1	Commer RS-2 (3)	RS-3	General Firm Service RS-5	NGV RS-6	Subtotal	Seasonal RS-4	General Interruptible RS-7 (9)	Lower Mainland RS-1 to RS-7 <u>Total</u> (10)	Term & Spot Gas Sales RS-14	Off-System Interruptible Sales RS-30 (12)	Lower Mainland RS-1 to RS-7, RS-14 & RS-30 Total	All Servio RS-1 to RS-7 Summary	ce Areas All Rate Schedules Summary
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)		
1 2	LOWER MAINLAND SERVICE AREA														
3 4	Midstream (MCRA) Sales Volumes (TJ)	51,034.9	16,698.1	11,620.4	2,419.2	88.6	81,861.2	74.8	8.1	81,944.1	541.2	27,471.5	109,956.8	108,178.8	136,418.3
5	MCRA Gas Costs Incurred (\$000)														
7 8	Midstream Commodity Costs Midstream Tolls and Fees	\$ 7,212.1 \$ 743.0	\$ 2,359.7 \$ 243.1	5 1,642.2 169.2	\$ 341.9 35.2	\$ 12.5 1.3	\$ 11,568.4 1,191.7	\$ 1.7 0.3	•	\$ 11,570.2 1,192.1	\$ 3,512.4 82.3		\$ 163,694.1 4,773.5	\$ 15,248.2 1,572.4	\$ 168,842.6 5,188.4
9	Midstream Mark to Market- Hedges Loss / (Gain)		-	-	-		-				-	-			
10	Total Midstream Variable Costs	\$ 7,955.1	<u>\$ 2,602.8</u>	5 1,811.3	\$ 377.1	<u>\$ 13.8</u>	\$ 12,760.1	<u>\$ 1.9</u>	\$ 0.2	\$ 12,762.3	\$ 3,594.7	\$ 152,110.7	\$ 168,467.6	\$ 16,820.6	<u>\$ 174,031.1</u>
11 12 13 14 15 16	Midstream Storage - Fixed On/Off System Sales Margin (RS-14 & RS-30) GSMIP Incentive Sharing Pipeline Demand Charges Core Administration Costs - 70%	\$ 18,686.9 \$ (2,253.2) 488.0 33,745.2 756.9	6,158.6 \$ (742.6) 160.8 11,121.3 249.5	5 3,542.9 (427.2) 92.5 6,397.8 143.5	\$ 527.1 (63.6) 13.8 951.8 21.3	\$ 9.7 (1.2) 0.3 17.4 0.4	\$ 28,925.1 (3,487.7) 755.4 52,233.6 1,171.6	\$ - - - -	\$ - - - -	\$ 28,925.1 (3,487.7) 755.4 52,233.6 1,171.6	\$ - - - - -	\$- - - -	\$ 28,925.1 (3,487.7) 755.4 52,233.6 1,171.6	\$ 38,292.2 (4,617.2) 1,000.0 68,362.6 1,551.0	, .
17	Total Midstream Fixed Costs	\$ 51,423.8	<u>\$ 16,947.7</u> <u></u>	9,749.5	\$ 1,450.4	\$ 26.6	\$ 79,597.9	<u>\$</u> -	\$-	\$ 79,597.9	\$-	\$-	\$ 79,597.9	\$ 104,588.6	\$ 104,588.6
18 19 20 21 22 23 24	Pre-tax Amort. MCRA Deficit/(Surplus) as of Apr 1, 2009	<u>\$ (12,332.6) 5</u> <u>\$ 47,046.2</u> 5					\$ <u>(19,089.4</u>) <u>\$73,268.6</u>	<u>\$</u> - <u>\$1.9</u>	<u>\$</u> <u>\$0.2</u>	\$ <u>(19,089.4</u>) <u>\$73,270.8</u>	<u>\$</u> - <u>\$3,594.7</u>	<u>\$</u> - <u>\$152,110.7</u>	\$ (19,089.4) \$ 228,976.1		<u>\$ (25,271.3)</u> <u>\$ 253,348.4</u>
25	MCRA Gas Costs Incurred (\$/GJ)														
26 27 28 29	Midstream Commodity Costs Midstream Tolls and Fees Midstream Mark to Market- Hedges Loss / (Gain) Total Midstream Variable Costs	\$ 0.1413 5 \$ 0.0146 5 <u>\$ - 5</u> \$ 0.1559 5	\$ 0.0146 \$ \$ - <u>\$</u>	6 0.0146 -	•	\$ 0.0146 \$ -	,								
30 31 32 33 34 35 36	Midstream Storage - Fixed On/Off System Sales Margin (RS-14 & RS-30) GSMIP Incentive Sharing Pipeline Demand Charges Core Administration Costs - 70% Total Midstream Fixed Costs Pre-tax Amort. MCRA Deficit/(Surplus) as of Apr 1, 2009 MCRA Incurred Costs (\$/GJ)	\$ 0.3662 \$ (0.0442) \$ 0.0096 \$ 0.6612 \$ 0.0148 \$ 1.0076 \$ (0.2417) \$ 0.9218	0.3688 \$ 0.03688 \$ 0.0445) \$ 0.0096 \$ 0.6660 \$ 0.0149 \$ 1.0149 \$ 0.2434) \$	0.3049 0.0368) 0.0080 0.5506 0.0123 0.8390 0.2012)	\$ 0.2179 \$ (0.0263) \$ 0.0057	\$ 0.1089 \$ (0.0131) \$ 0.0028 \$ 0.1967 \$ 0.0044 \$ 0.2998	\$ 0.3533 \$ (0.0426) \$ 0.0092								

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Tab 2 Table B Page 1.0

TERASEN GAS INC. - INLAND SERVICE AREA MIDSTREAM COST RECONCILIATION ACCOUNT ("MCRA") MIDSTREAM COST RECOVERY CHARGE FLOW-THROUGH BY RATE SCHEDULE FOR THE FORECAST PERIOD APRIL 1, 2009 to MARCH 31,2010

Tab 2

Table B

Page 1.1

Line No.	Particulars (1)	Residential RS-1 (2)	Comme RS-2 (3)	rcial RS-3 (4)	General Firm Service RS-5 (5)	NGV RS-6 (6)	Subtotal (7)	Seasonal RS-4 (8)	General Interruptible RS-7 (9)	Inland RS-1 to RS-7 Total (10)	Term & Spot Gas Sales RS-14 (11)	Off-System Interruptible Sales RS-30 (12)	Inland RS-1 to RS-7, & RS-14 Total (13)
1 2 3	INLAND SERVICE AREA Midstream (MCRA) Sales Volumes (TJ)	15,689.1	5,376.4	1,939.2	410.5	11.9	23,427.0	138.3	4.0	23,569.3	226.8	-	23,796.1
4 5 6	MCRA Gas Costs Incurred (\$000)												
7 8 9	Midstream Commodity Costs Midstream Tolls and Fees Midstream Mark to Market- Hedges Loss / (Gain)	\$ 2,129.8 \$ 228.3	729.9 S 78.3	\$ 263.3 28.2 -	\$ 55.7 \$ 6.0 -	\$ 1.6 0.2 -	\$ 3,180.3 341.0 -	\$ 2.3 0.5		\$ 3,182.7 341.5 -	\$ 1,470.5 34.6		\$ 4,653.2 376.1
10 11	Total Midstream Variable Costs	\$ 2,358.2 \$	808.1	\$ 291.5	\$ 61.7	\$ 1.8	\$ 3,521.2	\$ 2.8	\$ 0.1	\$ 3,524.2	<u>\$ 1,505.1</u>	\$ -	\$ 5,029.2
12 13 14 15 16	Midstream Storage - Fixed On/Off System Sales Margin (RS-14 & RS-30) GSMIP Incentive Sharing Pipeline Demand Charges Core Administration Costs - 70%	\$ 5,739.0 \$ (692.0) 149.9 9,881.8 232.5	1,981.0 \$ (238.9) 51.7 3,411.0 80.2	\$ 590.7 (71.2) 15.4 1,017.0 23.9	\$ 89.3 \$ (10.8) 2.3 153.8 3.6	\$ 1.3 (0.2) 0.0 2.2 0.1	\$ 8,401.2 (1,013.0) 219.4 14,465.9 340.3	\$ - - - -	\$- - - - -	\$ 8,401.2 (1,013.0) 219.4 14,465.9 340.3	\$- - - -	\$ - - - - -	\$ 8,401.2 (1,013.0) 219.4 14,465.9 340.3
17 18 19	Total Midstream Fixed Costs	<u>\$ 15,311.1</u>	5,285.0	\$ 1,575.8	\$ 238.3	\$ 3.4	\$ 22,413.8	\$-	\$ -	\$ 22,413.8	\$-	\$ -	\$ 22,413.8
20 21	Pre-tax Amort. MCRA Deficit/(Surplus) as of Apr 1, 2009	<u>\$ (3,787.5)</u> <u>\$</u>	(1,307.4)	\$ (389.8)	<u>\$ (59.0</u>) <u>\$</u>	\$ <u>(0.9</u>)	<u>\$ (5,544.5</u>)	<u>\$</u> -	<u>\$ -</u>	<u>\$ (5,544.5</u>)	\$ -	\$ -	<u>\$ (5,544.5</u>)
22 23 24	MCRA Incurred Costs (\$/GJ)	<u>\$ 13,881.8</u>	4,785.8	\$ 1,477.5	<u>\$ 241.1</u>	<u>§ 4.4</u>	<u>\$ 20,390.6</u>	\$ 2.8	<u>\$0.1</u>	<u>\$ 20,393.5</u>	<u>\$ 1,505.1</u>	<u>\$</u> -	<u>\$21,898.5</u>
25	Midstream Cost Recovery Charge (\$/GJ)												
26 27 28 29	Midstream Commodity Costs Midstream Tolls and Fees Midstream Mark to Market- Hedges Loss / (Gain) Total Midstream Variable Costs	\$ 0.1358 \$ \$ 0.0146 \$ <u>\$ - \$</u> \$ 0.1503 \$		\$ 0.0146 \$ -	\$ 0.1358 \$ \$ 0.0146 \$ \$ - \$ \$ 0.1503 \$	\$ 0.0146 \$ -	\$ 0.1358 \$ 0.0146 \$ - \$ 0.1503						
30 31 32 33 34 35	Midstream Storage - Fixed On/Off System Sales Margin (RS-14 & RS-30) GSMIP Incentive Sharing Pipeline Demand Charges Core Administration Costs - 70% Total Midstream Fixed Costs	\$ 0.3658 \$ \$ (0.0441) \$ \$ 0.0096 \$ \$ 0.6299 \$ \$ 0.0148 \$ \$ 0.9759 \$	(0.0444) \$ 0.0096 \$ 0.6344 \$	\$ (0.0367) \$ 0.0080 \$ 0.5245 \$ 0.0123		\$ (0.0131) \$ 0.0028 \$ 0.1874 \$ 0.0044	\$ (0.0432)						
36	Pre-tax Amort. MCRA Deficit/(Surplus) as of Apr 1, 2009 MCRA Incurred Costs (\$/GJ)	\$ 0.9739 \$ \$ (0.2414) \$ \$ 0.8848 \$	(0.2432)	\$ (0.2010)	\$ (0.1436)	\$ (0.0718)							

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TERASEN GAS INC. - COLUMBIA SERVICE AREA MIDSTREAM COST RECONCILIATION ACCOUNT ("MCRA") MIDSTREAM COST RECOVERY CHARGE FLOW-THROUGH BY RATE SCHEDULE FOR THE FORECAST PERIOD APRIL 1, 2009 to MARCH 31,2010 (FEBRUARY 24, 2009 FORWARD PRICING)

Line No.	Particulars	Re	esidential RS-1		Comme RS-2		 ?S- 3	s	General Firm Service RS-5		IGV S-6	s	ubtotal	Seasor RS-4		General Interruptible RS-7	RS	-1 to RS-7 Total	Spo Si R	orm & ot Gas ales S-14	Interr S R	System uptible Sales SS-30		Columbia 1 to RS-7 Total
	(1)		(2)		(3)		(4)		(5)		(6)		(7)	(8)		(9)		(10)	(11)		(12)		(13)
1 2	COLUMBIA SERVICE AREA																							
	Midstream (MCRA) Sales Volumes (TJ)		1,720.0		678.6		230.4		36.4		-		2,665.4		-	-		2,665.4		-		-		2,665.4
4 5 6	MCRA Gas Costs Incurred (\$000)																							
7	Midstream Commodity Costs	\$	319.6	\$	126.1	\$	42.8	\$	6.8	\$	-	\$	495.3	\$	-	\$-	\$	495.3	\$	-	\$	-	\$	495.3
8	Midstream Tolls and Fees		25.1		9.9		3.4		0.5		-		38.9		-	-		38.9		-		-		38.9
9	Midstream Mark to Market- Hedges Loss / (Gain)	_	-		-		-				-	_	-		-		-			-		-	_	-
10 11	Total Midstream Variable Costs	\$	344.7	\$	136.0	\$	46.2	\$	7.3	\$	-	\$	534.2	\$	-	<u>\$ -</u>	\$	534.2	\$	-	<u>\$</u>	-	\$	534.2
12	Midstream Storage - Fixed	\$	634.8	\$	252.3	\$	70.8	\$	8.0	\$	-	\$	965.9	\$	-	\$-	\$	965.9	\$	-	\$	-	\$	965.9
13	On/Off System Sales Margin (RS-14 & RS-30)		(76.5)		(30.4)		(8.5)		(1.0)		-		(116.5)		-	-		(116.5)		-		-		(116.5)
14	GSMIP Incentive Sharing		16.6		6.6		1.8		0.2		-		25.2		-	-		25.2		-		-		25.2
15	Pipeline Demand Charges		1,093.0		434.4		121.9		13.8		-		1,663.2		-	-		1,663.2		-		-		1,663.2
16	Core Administration Costs - 70%		25.7		10.2		2.9		0.3		-		39.1		-			39.1		-		-		39.1
17	Total Midstream Fixed Costs	\$	1,693.6	\$	673.1	\$	188.9	\$	21.3	\$	-	\$	2,576.9	\$	-	\$ -	\$	2,576.9	\$	-	\$	-	\$	2,576.9
18																								
19 20	Pre-tax Amort. MCRA Deficit/(Surplus) as of Apr 1, 2009	\$	(418.9)	\$	(166.5)	\$	(46.7)	\$	(5.3)	\$	-	\$	(637.5)	\$	-	<u>\$ -</u>	\$	(637.5)	\$	-	\$	-	\$	(637.5)
21																								
	MCRA Incurred Costs (\$/GJ)	\$	1,619.4	\$	642.6	\$	188.4	\$	23.4	\$	-	\$	2,473.7	\$		\$-	\$	2,473.7	\$	-	\$	-	\$	2,473.7
23																								
24																								
	Midstream Cost Recovery Charge (\$/GJ)										d Rate													
26	Midstream Commodity Costs	\$	0.1858			*		\$		*	0.1358		0.1858											
27	Midstream Tolls and Fees	\$		\$ \$				\$			0.0146		0.0146											
28	Midstream Mark to Market- Hedges Loss / (Gain)	<u>\$</u>	-	<u> </u>		<u>\$</u>	-	<u>\$</u>		<u>\$</u>	-	<u>\$</u>	-											
29	Total Midstream Variable Costs	\$		\$		<u> </u>		<u>\$</u>			0.1503	\$	0.2004											
30	Midstream Storage - Fixed	\$		\$			0.3073			*	0.1088	,	0.3624											
31	On/Off System Sales Margin (RS-14 & RS-30)	\$	(0.0445)		(0.0448)		(0.0371)		(0.0265)		0.0131)		(0.0437)											
32	GSMIP Incentive Sharing	\$	0.0096	\$	0.0097	\$	0.0080	Ф	0.0057	Ф	0.0028	Þ	0.0095											

0.3781 \$

0.0089 \$

0.5859 \$

(0.1<u>449</u>) <u>\$</u>

0.6414 \$

0.1874 \$

0.0044 \$

0.2903 \$

(0.0718) \$

0.3688 \$

0.6240

0.0147

0.9668

(0.2392)

0.9281

GSMIP Incentive Sharing 32 33 Pipeline Demand Charges

34 Core Administration Costs - 70%

Total Midstream Fixed Costs 35

36 Pre-tax Amort. MCRA Deficit/(Surplus) as of Apr 1, 2009 \$

\$

\$

\$

\$

0.6355 \$

0.0149 \$ 0.9847 \$

(0.2436) \$

0.9415 \$

0.6401 \$ 0.5292 \$

0.0151 \$ 0.0124 \$

0.9918 \$ 0.8199 \$

(0.2453) \$ (0.2028) \$

0.9469 \$ 0.8175 \$

37 MCRA Incurred Costs (\$/GJ)

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Tab 2 Table B

Page 1.2

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS CCRA MONTHLY BALANCES WITH PROPOSED RATES (AFTER VOLUME ADJUSTMENTS) FOR THE FORECAST PERIOD APRIL 1, 2009 TO MARCH 31, 2011 FEBRUARY 24, 2009 FORWARD PRICES

\$(Millions)

Line No.	(1)	(2)	(3)	(4)		(5)	((6)	(7	7)	(8)	(9	9)	(10)	(11)		(12	2)	(13)	(1	4)
1 2			orded t-08	Reco Nov		Recorded Dec-08		corded an-09		ected b-09	Proje Mar															
3	CCRA Balance - Beginning (Pre-tax) ^(1*)	\$	(50)	\$	(46)	\$ (40))\$	(33)	\$	(29)	\$	(30)														
4	Gas Costs Incurred	\$	58	\$	64	\$ 68	\$	63	\$	55	\$	57														
5	Revenue from EXISTING Recovery Rates	\$	(54)	\$	(58)	\$ (61)) \$	(60)	\$	(56)	\$	(62)														
6 7	CCRA Balance - Ending (Pre-tax) ^(2*)	\$	(46)	\$	(40)	\$ (34))\$	(29)	\$	(30)	\$	(36)														
8	CCRA Balance - Ending (After-tax) ^(3*)	\$	(32)	\$	(28)	\$ (23)) \$	(21)	\$	(21)	\$	(25)														
9 10 11 12 13		For	ecast r-09	Fore May	cast	Forecast Jun-09	Fo	precast	Fore	ecast g-09	Fore Sep	ecast	Fore Oct-		Fore		Forec		Foreca Jan-1(Foreo Feb-			ecast ar-10		
14	CCRA Balance - Beginning (Pre-tax) (1*)	\$	(36)		(40)			(46)		(48)		(50)		(51)		(52)		(44)		33)		(21)		(11)		(36)
15	Gas Costs Incurred	\$	38		40		, ¢ \$	41		42		41		43		(<u>52</u>)		(1 4) 54		55 55		50		55		(00) 547
16	Revenue from PROPOSED Recovery Rates	\$	(42)		(43)			(43)	*	(43)		(42)		(43)		(42)		(43)		43)		(39)	•	(43)		(512)
10	CCRA Balance - Ending (Pre-tax) ^(2*)	\$	(40)		(43))\$	(48)		(50)		(51)		(52)		(44)		(33)		21)		(11)		<u>(</u> +3) 1		1
18	······	<u> </u>	()	Ŷ	()	φ (10)	/ •	(10)	Ŷ	(00)	Ŷ	(01)	Ŷ	(02)	Ŷ	()	Ŷ	(00)	Ψ (-	/	Ŷ	()	Ŷ	•	Ŷ	<u> </u>
19	CCRA Balance - Ending (After-tax) ^(3*)	\$	(28)	\$	(30)	\$ (32)) \$	(33)	\$	(35)	\$	(36)	\$	(36)	\$	(31)	\$	(23)	\$ (*	15)	\$	(8)	\$	0	\$	0
20 21 22 23 24			ecast r-10	Fore May		Forecast Jun-10		orecast Jul-10		ecast g-10	Fore Sep		Fore Oct-		Fore		Forec Dec-		Foreca Jan-11		Foreo Feb-			ecast ar-11	Ap t	otal :-10 o r-11
25	CCRA Balance - Beginning (Pre-tax) (1*)	\$	1	\$	3	\$6	\$	9	\$	13	\$	17	\$	21	\$	26	\$	36	\$ 4	48	\$	61	\$	73	\$	1
26	Gas Costs Incurred	\$	43	\$	45	\$ 44	\$	46	\$	46	\$	45	\$	47	\$	51	\$	55	\$!	56	\$	50	\$	54	\$	584
27	Revenue from PROPOSED Recovery Rates	\$	(41)	\$	(42)	\$ (41)) \$	(42)	\$	(42)	\$	(41)	\$	(42)	\$	(41)	\$	(42)	\$ (4	42)	\$	(38)	\$	(42)	\$	(499)
28 29	CCRA Balance - Ending (Pre-tax) ^(2*)	\$	3	\$	6	\$ 9	\$	13	\$	17	\$	21	\$	26	\$	36	\$	49	\$ (51	\$	73	\$	85	\$	85
29 30	CCRA Balance - Ending (After-tax) ^(3*)	\$	2	\$	4	\$ 6	\$	9	\$	12	\$	15	\$	19	\$	26	\$	35	\$ 4	45	\$	54	\$	62	\$	62

Notes: Slight differences in totals due to rounding.

(1*) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts (Jan 1, 2008, 31.0%, Jan 1, 2009, 30.0%, Jan 1, 2010, 28.5%, and Jan 1, 2011, 26.5%).

(2*) For rate setting purpose CCRA pre tax balances include grossed up projected deferred interest as at March 31, 2009.

(3*) For rate setting purpose CCRA after tax balances are independently grossed-up to reflect pre-tax amounts.

Tab 3 Page 1

Terasen Gas Inc. Lower Mainland, Inland and Columbia CCRA After-Tax Monthly Balances Recorded to January 2009 and Projected to March 2011

\$60 CCRA After-Tax Balances at Existing October 1, 2008 Rates with February 24, 2009 forward prices \$40 CCRA After-Tax Balances at Proposed April 1, 2009 Rates with February 24, 2009 forward prices \$20 \$0 (\$20) \$ Millions (\$40) (\$60) (\$80) (\$100) (\$120) (\$140) 780, Esp War ber Way, mu, mu brow 280, 04, Mon, Dec. 780, Esp. War, ber Way, mu, mu brow 286, 04, Mon, Dec. 780, Esp. War,

Tab 3 Page 1.1

TERASEN GAS INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS MCRA MONTHLY BALANCES AT PROPOSED CCRA RATES APR 1, 2009 (AFTER VOLUME ADJUSTMENTS FOR THE FORECAST PERIOD APRIL 1, 2009 TO MARCH 31, 2011 FEBRUARY 24, 2009 FORWARD PRICES

\$(Millions)

Line No.	(1)		(2)	(3)		(4)	(5)	(6)	(7)		(8)		(9)	(10)	(11)		(12)	(13)	(14)	
1 2	MODA Delance Designing (Dec. tor.) ⁽¹⁾																	Recorded Oct-08	N	ecorded lov-08	De	corded		
3	MCRA Balance - Beginning (Pre-tax) ^(1*) Gas Costs Incurred																	\$ (7) \$ 58		(22) 111		(9) 118		
5	Revenue from EXISTING Recovery Rates																	\$ (72)		(99)	*	(144)		
6	MCRA Balance - Ending (Pre-tax) ^(2*)																-	\$ (22)	<u> </u>	(9)		(34)		
7																	:	+ ()	Ť	(-)	<u> </u>	(0.1)		
8	MCRA Balance - Ending (After-tax)																	\$ (15)	\$	(6)	\$	(24)		
9																	-							
10																								
11 12		Por	corded	Project	od	Projected	For	ecast	For	ecast	Foreca	ot	Forecast	Fo	recast	Fore	oot	Forecast	E	orecast	For	ecast	Total	
12			in-09	Feb-0		Mar-09		r-09		y-09	Jun-0		Jul-09		ug-09	Sep		Oct-09		lov-09		ecasi ec-09	2009	
14	MCRA Balance - Beginning (Pre-tax) (1*)	\$	(34)		27)			(25)		(20)		(8)		\$	32	· · · ·		\$ 74		78	\$	71		34)
15	Gas Costs Incurred	φ \$	122		73			19		(20)		(1))\$	(1)		0	\$ 12		52	Ψ \$			75
16	Revenue from EXISTING Recovery Rates	\$	(115)		70)			(14)	•	14		19		, . \$	24		19		\$	(60)	\$	(74)		89)
17	MCRA Balance - Ending (Pre-tax) ^(2*)	\$	(27)		24)			(20)		(8)				\$	55	\$	74	\$ 78		71		50		50
18																								_
19	MCRA Balance - Ending (After-tax) ^(3*)	\$	(19)	\$ (17)	\$ (18)	\$	(14)	\$	(5)	\$	7	\$ 22	\$	38	\$	52	\$ 55	\$	50	\$	35	\$:	35
20 21 22																								
23		Fo	recast	Foreca	st	Forecast	Fore	ecast	Fore	ecast	Foreca	st	Forecast	Fo	recast	Fored	cast	Forecast	Fo	precast	For	ecast	Total	i i
24		Ja	in-10	Feb-1	0	Mar-10	Ap	r-10	Ma	y-10	Jun-1	0	Jul-10	A	ug-10	Sep	·10	Oct-10	N	lov-10	De	ec-10	2010	
25	MCRA Balance - Beginning (Pre-tax) ^(1*)	\$	49			\$8	\$	(4)		(4)			\$ 19		34	\$	51	• • •		59	\$	52		49
26	Gas Costs Incurred	\$	62	*		•		17	•	(3)			\$ (2		(2)		(7)			67	\$		+	88
27	Revenue from EXISTING Recovery Rates	\$	(85)		68)			(17)		13		-	-	\$	19		16	. ()		(74)		(77)		01)
28	MCRA Balance - Ending (Pre-tax) ^(2*)	\$	25	\$	8	\$ (4)	\$	(4)	\$	5	\$	19	\$ 34	\$	51	\$	60	\$ 59	\$	52	\$	36	\$	36
29 30	MCRA Balance - Ending (After-tax) ^(3*)	¢	18	¢	6	¢ (2)	¢	(2)	¢	4	¢	12	¢ 05	\$	36	¢	12	\$ 42	¢	20	¢	25	¢ ·	25
30	MORA Balance - Linung (Alter-lax)	\$	18	Φ	Ö	\$ (3)	Φ	(3)	Φ	4	Φ	13	ə 25	Φ	30	Φ	43	ə 42	\$	38	Φ	25	φ.	25

Notes: Slight differences in totals due to rounding.

(1*) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts (Jan 1, 2008, 31.0%, Jan 1, 2009, 30.0%, Jan 1, 2010, 28.5%).

(2*) For rate setting purpose MCRA pre tax balances include grossed up projected deferred interest as at February 14, 1900.

(3*) For rate setting purpose MCRA after tax balances are independently grossed-up to reflect pre-tax amounts.

TERASEN GAS INC. 2008 ANNUAL REVIEW - AMENDMENT TO DELIVERY RATES, APRIL 1, 2009 2008-2009 EXTENSION OF THE 2004 - 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

Amendment to 2009 Delivery Rates, April 1, 2009 SUMMARY OF RATE CHANGE REQUIRED FOR THE YEAR ENDING DECEMBER 31, 2009

				2	009		
Line		2009 Approved			Bypass and		
No.	Particulars	Order No. G-191-08	Core	Non-Core	Special Rates	Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 2	RATE CHANGE REQUIRED						
3	Gas Sales and Transportation Revenue,						
4	At Prior Year's Rates	\$1,654,298	\$1,590,880	\$57,107	\$12,045	\$1,660,032	\$5,734
5							
6	Add - Other Revenue Related to SCP Third Party						
7	Revenue / Terasen Gas (Vancouver Island)	14,526	-		14,526	14,526	
8							
9	Total Revenue	1,668,824	1,590,880	57,107	26,571	1,674,558	5,734
10	Lass Orat of Ora	(4,407,000)	(4.405.500)	(4,004)	(700)	(4, 4,07, 000)	
11	Less - Cost of Gas	(1,187,999)	(1,185,526)	(1,681)	(792)	(1,187,999)	
12 13	Gross Margin	\$480,825	\$405,354	\$55,426	\$25,779	\$486,559	\$5,734
14		φ+00,020	φ+00,004	φ00,420	φ20,110	φ100,000	φ0,704
15	Revenue Deficiency (Surplus)	\$35,120	\$25,852	\$3,535	\$0	\$29,387	(\$5,733
16		+	+ -)	+ - ,			(+-)
17	Revenue Deficiency (Surplus) as a % of Gross Margin	7.30%	6.38%	6.38%	0.00%	6.04%	-1.26%
18	, , , , , , , , , , , , , , , , , , ,						
19	Revenue Deficiency (Surplus) as a % of Total Revenue	2.10%	1.63%	6.19%	0.00%	1.75%	-0.35%

A-4 Gas Sales & Transportation Volumes

TERASEN GAS INC.

(\$000s)

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Section A Tab 1 Page 5

TERASEN GAS INC. 2008 ANNUAL REVIEW – AMENDMENT TO DELIVERY RATES, APRIL 1, 2009 2008-2009 EXTENSION OF THE 2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

	TERASEN GAS INC.						Ar	nendment to 200	09 Delivery Rates	s, April 1, 2009	Section A
	REVENUE UNDER 2008 RATES AND REVISED AP			\							Tab 4 Page 14
	FOR THE YEAR ENDING DECEMBER 31, 2009	TRIE 1, 2009 RATE	S (NOII-Bypass)							Fage 14
	(\$000s)										
			Rev	enue	Gross I	Margin	Increase / (Decrease)		Rev	enue
			At January 1	I, 2008 Rates	At January 1	, 2008 Rates	6.38%	of Margin	Average	April 1, 2	009 Rates
Line			Average	Revenue	Average	Margin		Revenue	Number of	Average	Revenue
No.	Particulars	Terajoules	\$/GJ	(\$000s)	\$/GJ	(\$000s)	\$/GJ	(\$000s)	Customers	\$/GJ	(\$000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	NON-BYPASS										
2	Core and Non-Core Sales										
3	Schedule 1 - Residential	68,497.0	\$15.199	\$1,041,088	\$4.231	\$289,788	\$0.270	\$18,481	751,818	\$15.469	\$1,059,569
4	Schedule 2 - Small Commercial	22,870.3	14.138	323,342	3.210	73,419	0.205	4,682	75,300	14.343	328,024
5	Schedule 3 - Large Commercial	14,014.7	13.253	185,737	2.506	35,122	0.160	2,240	4,709	13.413	187,977
6 7	Total Schedules 1, 2 and 3	105,382.0		1,550,167		398,329		25,403	831,827		1,575,570
8	Schedule 4 - Seasonal Service	214.4	12.533	2.687	1.936	415	0.121	26	21	12.654	2,713
9	Schedule 5 - General Firm Service	2,866.2	12.789	36,655	2.187	6,267	0.140	400	283	12.929	37,055
10		,		,		-, -					- ,
11	Industrials										
12	Schedule 7 - Interruptible	11.9	13.361	159	2.605	31	0.168	2	2	13.529	161
13											
14	Total Industrials	11.9		159		31		2	2		161
15											
16	Schedule 6 - N G V Fuel - Stations	100.3	13.669	1,371	3.420	343	0.209	21	32	13.878	1,392
17											
18	Total Industrials	100.3		1,371		343		21	32		1,392
19		100 574 0		4 504 000		405.005					1 010 001
20 21	Total Core and Non-Core Sales	108,574.8		1,591,039		405,385		25,852	832,166		1,616,891
21	Core and Non-Core Transportation Service										
23	Schedule 22 - Firm Service	7,217.1	0.667	4,811	0.621	4,481	0.040	286	13	0.707	5,097
24	- Interruptible Service	10,949.6	0.786	8,602	0.740	8,098	0.040	517	23	0.833	9,119
25	Schedule 23 - Large Commercial	6,108.7	2.544	15,540	2.513	15,349	0.160	980	1,381	2.704	16,520
26	Schedule 25 - Firm Service	12,170.8	1.855	22,582	1.824	22,200	0.116	1,416	583	1.971	23,998
27	Schedule 27 - Interruptible Service	4,677.6	1.157	5,413	1.126	5,267	0.072	336	98	1.229	5,749
28		.,		2,.10		-,		250	50		2,. 10
29	Total Core and Non-Core T-Service	41,123.8		56,948		55,395		3,535	2,098		60,483
30 31	Total Sales & Transportation Service	149,698.6		\$1,647,987		\$460,780		\$29,387	834,263		\$1,677,374
	·····										

A-4 Gas Sales & Transportation Volumes

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TAB 4 PAGE 2

TERASEN GAS INC. 2008 ANNUAL REVIEW – AMENDMENT TO DELIVERY RATES, APRIL 1, 2009 2008-2009 EXTENSION OF THE 2004 - 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

	TERASEN GAS INC.						A	mendment to 20	09 Delivery Rates	, April 1, 2009	Section A
	REVENUE UNDER 2008 RATES AND REVISED APR FOR THE YEAR ENDING DECEMBER 31, 2009 (\$000s)	IL 1, 2009 RATE	ES (Bypass)								Tab 4 Page 14.1
			Reve	enue	Gross M	/largin	Increase /	(Decrease)		Reve	enue
			At January 1	, 2008 Rates	At January 1,	2008 Rates	0.00%	of Margin	Average	April 1, 20	009 Rates
Line			Average	Revenue	Average	Margin		Revenue	Number of	Average	Revenue
No.	Particulars	Terajoules	\$/GJ	(\$000)	\$/GJ	(\$000s)	\$/GJ	(\$000)	Customers	\$/GJ	(\$000)
	С	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	BYPASS AND SPECIAL RATES										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	9,363.4	0.135	1,267	0.128	1,194	-	-	9	0.135	1,267
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	194.7	0.236	46	0.149	29	-	-	1	0.236	46
6	Burrard Thermal - Firm	1,557.4	6.398	9,965	6.379	9,934	-	-	1		9,965
7	TGVI - Firm	32,408.7	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	829.5	0.925	767	0.901	747	-	-	7	0.925	767
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	44,353.7		12,045		11,904		-	20		12,045
12											
13	Total Non-Captive Sales and										
14 15	Transportation Service	44,353.7		12,045		11,904			20		12,045
15	TOTAL CAPTIVE AND NON-CAPTIVE SALES AND										
17	TRANSPORTATION SERVICE	194,052.3		\$1,660,032		\$472,684		\$29,387	834,283		\$1,689,419

A-4 Gas Sales & Transportation Volumes

Page 14.1

TERASEN GAS INC. 2008 ANNUAL REVIEW – AMENDMENT TO DELIVERY RATES, APRIL 1, 2009 2008-2009 EXTENSION OF THE 2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

	(\$000s)		Revised A	pril 1, 2009	Order No.	G-191-08				Rate Rider C	Calculation	
		Forecast Annual Volume	6.38%	Increase of Margin	7.72%	Increase of Margin	Deficienc	d Revenue by by Rate edule	Jan 1-Mar 31 Volumes	Forecast Jan 1-Mar 31 Overrecovery	Forecast Volumes Apr 1 - Dec 31	Proposed Rate Rider
ine				Revenue		Revenue		Revenue		Revenue		
No.	Particulars	TJ	\$/GJ	(\$000s)	\$/GJ	(\$000s)	\$/GJ	(\$000s)	TJ	(\$000s)	TJ	\$/GJ
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	NON-BYPASS						(5) - (3)	(6) - (4)		(7) x (9)		(10)/(11)
2	Core and Non-Core Sales											
3	Schedule 1 - Residential	68,497.0	\$0.270	\$18,481	\$0.322	\$22,039	\$0.052	\$3,558	27,449.8	\$1,427	40,835.8	(\$0.035)
4	Schedule 2 - Small Commercial	22,870.3	0.205	4,682	0.245	5,596	0.040	914	9,644.0	\$386	13,397.7	(0.029)
5	Schedule 3 - Large Commercial	14,014.7	0.160	2,240	0.191	2,682	0.031	442	5,917.7	\$183	8,629.0	(0.021)
6 7	Total Schedules 1, 2 and 3	105,382.0		25,403		30,317		4,914	43,011.5	\$1,997	62,862.5	
8	Schedule 4 - Seasonal Service	214.4	0.121	26	0.149	32	0.028	6	5.2	\$0	209.2	(0.001)
9 10	Schedule 5 - General Firm Service	2,866.2	0.140	400	0.169	483	0.029	83	1,136.2	\$33	1,881.0	(0.018)
11	Industrials											
12	Schedule 7 - Interruptible	11.9	0.168	2	0.168	2	-	0	38.5	\$0	11.8	-
13 14	Total Industrials	11.9		2		2			38.5	\$0	11.8	
15									00.0	\		
16 17	Schedule 6 - N G V Fuel - Stations	100.3	0.209	21	0.259	26	0.050	5	28.6	\$1	76.5	(0.019)
18 19	Total Industrials	100.3		21		26		5	28.6	\$1	76.5	
20	Total Core and Non-Core Sales	108,574.8		25,852		30,860		5,008	44,220.1	\$2,031	65,041.0	
21 22	Core and Non-Core Transportation Service											
23	Schedule 22 - Firm Service	7,217.1	0.040	286	0.048	346	0.008	60	2,049.4	\$17	5,145.0	(0.003)
24	- Interruptible Service	10,949.6	0.047	517	0.057	625	0.010	108	3,607.4	\$36	7,820.4	(0.005)
25	Schedule 23 - Large Commercial	6,108.7	0.160	980	0.192	1,173	0.032	193	2,578.1	\$82	3,744.7	(0.022)
26	Schedule 25 - Firm Service	12,170.8	0.116	1,416	0.141	1,711	0.025	295	4,053.2	\$101	8,333.0	(0.012)
27	Schedule 27 - Interruptible Service	4,677.6	0.072	336	0.087	405	0.015	69	1,735.9	\$26	3,192.9	(0.008)
28 29	Total Core and Non-Core T-Service	41,123.8		3,535		4,260		725	14,023.9	\$263	28,236.0	
30												
31	Total Non-Bypass Sales & Transportation Service	149,698.6		\$29,387		\$35,120		\$5,733	58,244.0	\$2,294	93,277.0	

RATE SCHEDULE 1: DELIVERY MARGIN AND COMMODITY RESIDENTIAL SERVICE **EXISTING JANUARY 1, 2009 RATES** RELATED CHARGES CHANGES PROPOSED APRIL 1, 2009 RATES Line Lower Lower Lower Particulars Mainland Inland Columbia Mainland Inland Columbia Mainland Inland Columbia No. (3) (9) (1) (2) (4) (5) (6) (7) (8) (10) 1 Delivery Margin Related Charges 2 Basic Charge per month \$11.99 \$11.99 \$11.84 \$11.84 \$11.99 (\$0.15) (\$0.15) (\$0.15) \$11.84 3 4 Delivery Charge per GJ \$2.998 \$2.998 \$2.998 (\$0.037) (\$0.037) (\$0.037) \$2.961 \$2.961 \$2.961 5 Rider 3 ESM (\$0.132) (\$0.132) (\$0.132) \$0.000 \$0.000 \$0.000 (\$0.132) (\$0.132) (\$0.132) 6 Rider 4 Delivery Rate Refund (\$0.022) (\$0.022) (\$0.022) (\$0.013) (\$0.013) (\$0.013) (\$0.035) (\$0.035) (\$0.035) 7 Rider 5 RSAM \$0.001 \$0.001 \$0.001 \$0.000 \$0.000 \$0.000 \$0.001 \$0.001 \$0.001 Subtotal Delivery Margin Related Charges per GJ \$2.845 \$2.845 \$2.845 (\$0.050) \$2.795 \$2.795 \$2.795 8 (\$0.050) (\$0.050) 9 10 Commodity Related Charges 11 12 Midstream Cost Recovery Charge per GJ \$0.942 \$0.903 \$0.981 \$0.000 \$0.000 \$0.000 \$0.942 \$0.903 \$0.981 13 Rider 8 Unbundling Recovery \$0.073 \$0.073 \$0.073 \$0.000 \$0.000 \$0.000 \$0.073 \$0.073 \$0.073 14 Subtotal Midstream Related Charges per GJ \$1.015 \$0.976 \$1.054 \$0.000 \$0.000 \$0.000 \$1.015 \$0.976 \$1.054 15 16 Cost of Gas (Commodity Cost Recovery Charge) per GJ \$7.536 \$7.536 \$7.536 (\$1.574) (\$1.574) (\$1.574) \$5.962 \$5.962 \$5.962 17 18 Rider 1 Propane Surcharge (Revelstoke only) \$5.201 \$6.775 19 \$1.574 20 21 22 Cost of Gas Recovery Related Charges for Revelstoke \$13.640 \$0.000 \$13.640 23 per GJ (Includes Rider 1, excludes Riders 8)

TAB 5 PAGE 1 SCHEDULE 1

RATE SCHEDULE 2: DELIVERY MARGIN AND COMMODITY SMALL COMMERCIAL SERVICE RELATED CHARGES CHANGES **EXISTING JANUARY 1, 2009 RATES** PROPOSED APRIL 1, 2009 RATES Line Lower Lower Lower Particulars Mainland Inland Columbia Mainland Inland Columbia Mainland Inland Columbia No. (9) (1) (2) (3) (4) (5) (6) (7) (8) (10) 1 Delivery Margin Related Charges 2 Basic Charge per month \$25.15 \$25.15 \$25.15 \$24.84 \$24.84 (\$0.31) (\$0.31) (\$0.31) \$24.84 3 4 Delivery Charge per GJ \$2.510 \$2.510 \$2.510 (\$0.031) (\$0.031) (\$0.031) \$2.479 \$2.479 \$2.479 5 Rider 3 ESM (\$0.100) (\$0.100) (\$0.100) \$0.000 \$0.000 \$0.000 (\$0.100) (\$0.100) (\$0.100) 6 Rider 4 Delivery Rate Refund (\$0.017) (\$0.017) (\$0.017) (\$0.012) (\$0.012) (\$0.012) (\$0.029) (\$0.029) (\$0.029) 7 Rider 5 RSAM \$0.001 \$0.001 \$0.001 \$0.000 \$0.000 \$0.000 \$0.001 \$0.001 \$0.001 Subtotal Delivery Margin Related Charges per GJ \$2.394 \$2.394 \$2.394 (\$0.043) (\$0.043) (\$0.043) \$2.351 \$2.351 \$2.351 8 9 10 Commodity Related Charges 11 12 Midstream Cost Recovery Charge per GJ \$0.947 \$0.907 \$0.986 \$0.000 \$0.000 \$0.000 \$0.947 \$0.907 \$0.986 13 Rider 8 Unbundling Recovery (\$0.021) (\$0.021) (\$0.021) \$0.000 \$0.000 \$0.000 (\$0.021) (\$0.021) (\$0.021) 14 Subtotal Midstream Related Charges per GJ \$0.926 \$0.886 \$0.965 \$0.000 \$0.000 \$0.000 \$0.926 \$0.886 \$0.965 15 16 Cost of Gas (Commodity Cost Recovery Charge) per GJ \$7.536 \$7.536 \$7.536 (\$1.574) (\$1.574) (\$1.574) \$5.962 \$5.962 \$5.962 17 18 Rider 1 Propane Surcharge (Revelstoke only) \$4.106 \$5.680 19 \$1.574 20 21 22 Cost of Gas Recovery Related Charges for Revelstoke \$12.549 \$0.000 \$12.549 23 per GJ (Includes Rider 1, excludes Rider 8)

TAB 5 PAGE 2 SCHEDULE 2

RATE SCHEDULE 3: DELIVERY MARGIN AND COMMODITY LARGE COMMERCIAL SERVICE RELATED CHARGES CHANGES **EXISTING JANUARY 1, 2009 RATES** PROPOSED APRIL 1, 2009 RATES Line Lower Lower Lower Particulars Mainland Inland Columbia Mainland Inland Columbia Mainland Inland Columbia No. (3) (9) (1) (2) (4) (5) (6) (7) (8) (10) 1 Delivery Margin Related Charges 2 Basic Charge per month \$134.20 \$134.20 \$134.20 \$132.52 \$132.52 \$132.52 (\$1.68) (\$1.68) (\$1.68) 3 4 Delivery Charge per GJ \$2.163 \$2.163 \$2.163 (\$0.027) (\$0.027) (\$0.027) \$2.136 \$2.136 \$2.136 5 Rider 3 ESM (\$0.079) (\$0.079) (\$0.079) \$0.000 \$0.000 \$0.000 (\$0.079) (\$0.079) (\$0.079) 6 Rider 4 Delivery Rate Refund (\$0.013) (\$0.013) (\$0.013) (\$0.008) (\$0.008) (\$0.008) (\$0.021) (\$0.021) (\$0.021) Rider 5 RSAM \$0.001 \$0.000 \$0.000 \$0.001 \$0.001 \$0.001 7 \$0.001 \$0.001 \$0.000 Subtotal Delivery Margin Related Charges per GJ 8 \$2.072 \$2.072 \$2.072 (\$0.035) (\$0.035) (\$0.035) \$2.037 \$2.037 \$2.037 9 10 11 Commodity Related Charges 12 Midstream Cost Recovery Charge per GJ \$0.830 \$0.796 \$0.873 \$0.000 \$0.000 \$0.000 \$0.830 \$0.796 \$0.873 13 Rider 8 Unbundling Recovery (\$0.021) (\$0.021) (\$0.021) \$0.000 \$0.000 \$0.000 (\$0.021) (\$0.021) (\$0.021) 14 Subtotal Midstream Related Charges per GJ \$0.809 \$0.775 \$0.852 \$0.000 \$0.000 \$0.000 \$0.809 \$0.775 \$0.852 15 Cost of Gas (Commodity Cost Recovery Charge) per GJ \$7.536 \$7.536 (\$1.574) \$5.962 \$5.962 \$5.962 16 \$7.536 (\$1.574) (\$1.574) 17 18 19 Rider 1 Propane Surcharge (Revelstoke only) \$4.217 \$1.574 \$5.791 20 21 22 Cost of Gas Recovery Related Charges for Revelstoke \$12.549 \$0.000 \$12.549 23 per GJ (Includes Rider 1, excludes Rider 8)

TAB 5 PAGE 3 SCHEDULE 3

RATE SCHEDULE 4: DELIVERY MARGIN AND COMMODITY SEASONAL SERVICE **EXISTING JANUARY 1, 2009 RATES RELATED CHARGES CHANGES** PROPOSED APRIL 1, 2009 RATES Line Lower Lower Lower Mainland Mainland No. Particulars Inland Columbia Mainland Inland Columbia Inland Columbia (1) (2) (3) (4) (5) (6) (7) (8) (9) (10) Delivery Margin Related Charges 1 2 Basic Charge per month \$445.00 \$445.00 \$445.00 (\$6.00) (\$6.00) (\$6.00) \$439.00 \$439.00 \$439.00 3 Delivery Charge per GJ 4 5 (a) Off-Peak Period \$0.772 \$0.772 \$0.772 (\$0.010) (\$0.010) (\$0.010) \$0.762 \$0.762 \$0.762 6 (b) Extension Period \$1.558 \$1.558 \$1.558 (\$0.019) (\$0.019) (\$0.019) \$1.539 \$1.539 \$1.539 7 8 Rider 3 ESM (\$0.061) (\$0.061) (\$0.061) \$0.000 \$0.000 \$0.000 (\$0.061) (\$0.061) (\$0.061) 9 Rider 4 Delivery Rate Refund (\$0.006) (\$0.006) (\$0.006) \$0.005 \$0.005 \$0.005 (\$0.001) (\$0.001) (\$0.001) 10 Commodity Related Charges 11 12 **Commodity Cost Recovery Charge** 13 (a) Off-Peak Period \$7.536 \$7.536 \$7.536 (\$1.574) (\$1.574) (\$1.574) \$5.962 \$5.962 \$5.962 14 (b) Extension Period \$7.536 \$7.536 \$7.536 (\$1.574) (\$1.574) (\$1.574) \$5.962 \$5.962 \$5.962 15 16 Midstream Cost Recovery Charge per GJ 17 (a) Off-Peak Period \$0.670 \$0.644 \$0.720 \$0.000 \$0.000 \$0.000 \$0.670 \$0.644 \$0.720 18 (b) Extension Period \$0.670 \$0.644 \$0.720 \$0.000 \$0.000 \$0.000 \$0.670 \$0.644 \$0.720 19 20 21 Subtotal Off -Peak Commodity Related Charges per GJ 22 (a) Off-Peak Period \$8.256 (\$1.574) \$6.632 \$6.606 \$6.682 \$8.206 \$8.180 (\$1.574) (\$1.574) 23 (b) Extension Period \$8.206 \$8.180 \$8.256 (\$1.574) (\$1.574) (\$1.574) \$6.632 \$6.606 \$6.682 24 25 26 Balancing, Backstopping and UOR per BCUC Balancing, Backstopping and UOR per BCUC Order 27 Unauthorized Gas Charge per gigajoule Order No. G-110-00. No. G-110-00. 28 during peak period 29 30 31 Total Variable Cost per gigajoule between 32 (a) Off-Peak Period \$8.911 \$8.885 \$8.961 (\$1.579) (\$1.579) (\$1.579) \$7.332 \$7.306 \$7.382 \$9.697 (\$1.588) 33 (b) Extension Period \$9.671 \$9.747 (\$1.588) (\$1.588) \$8.109 \$8.083 \$8.159

TAB 5 PAGE 4 SCHEDULE 4

RATE SCHEDULE 5 DELIVERY MARGIN AND COMMODITY GENERAL FIRM SERVICE EXISTING JANUARY 1, 2009 RATES **RELATED CHARGES CHANGES** PROPOSED APRIL 1, 2009 RATES Line Lower Lower Lower Particulars Mainland Inland Columbia Mainland Inland Columbia Mainland Inland Columbia No. (3) (9) (1) (2) (4) (5) (6) (7) (8) (10) 1 Delivery Margin Related Charges 2 Basic Charge per month \$594.00 \$594.00 \$594.00 (\$7.00) (\$7.00) (\$7.00) \$587.00 \$587.00 \$587.00 3 4 Demand Charge per gigajoule \$14.840 \$14.840 \$14.840 (\$0.185) (\$0.185) (\$0.185) \$14.655 \$14.655 \$14.655 5 6 Delivery Charge per GJ \$0.600 \$0.600 \$0.600 (\$0.007) (\$0.007) (\$0.007) \$0.593 \$0.593 \$0.593 7 \$0.000 8 Rider 3 ESM (\$0.060) (\$0.060) (\$0.060) \$0.000 \$0.000 (\$0.060) (\$0.060) (\$0.060) 9 Rider 4 Delivery Rate Refund (\$0.009) (\$0.009) (\$0.009) (\$0.009) (\$0.009) (\$0.009) (\$0.018) (\$0.018) (\$0.018) 10 11 12 Commodity Related Charges Cost of Gas (Commodity Cost Recovery Charge) per GJ \$7.536 (\$1.574) \$5.962 \$5.962 \$5.962 13 \$7.536 \$7.536 (\$1.574) (\$1.574) 14 Midstream Cost Recovery Charge per GJ \$0.670 \$0.644 \$0.720 \$0.000 \$0.000 \$0.000 \$0.670 \$0.644 \$0.720 15 Subtotal Commodity Related Charges per GJ \$8.206 \$8.180 \$8.256 (\$1.574) (\$1.574) \$6.632 \$6.606 \$6.682 (\$1.574) 16 17 18 19 Total Variable Cost per gigajoule \$8.737 \$8.711 \$8.787 (\$1.590) (\$1.590) (\$1.590) \$7.147 \$7.121 \$7.197

TAB 5 PAGE 5 SCHEDULE 5

RATE SCHEDULE 6: DELIVERY MARGIN AND COMMODITY **NGV - STATIONS** EXISTING JANUARY 1, 2009 RATES RELATED CHARGES CHANGES PROPOSED APRIL 1, 2009 RATES Line Lower Lower Lower Particulars Mainland Inland Columbia Mainland Inland Columbia Mainland Inland Columbia No. (3) (6) (9) (1) (2) (4) (5) (7) (8) (10) 1 Delivery Margin Related Charges 2 Basic Charge per month \$62.00 \$62.00 \$62.00 (\$1.00) (\$1.00) (\$1.00) \$61.00 \$61.00 \$61.00 3 Delivery Charge per GJ \$3.441 \$3.398 4 \$3.441 \$3.441 (\$0.043) (\$0.043) (\$0.043) \$3.398 \$3.398 5 6 Rider 3 ESM (\$0.110) \$0.000 \$0.000 \$0.000 (\$0.110) (\$0.110) (\$0.110) (\$0.110) (\$0.110) Rider 4 Delivery Rate Refund 7 (\$0.020) (\$0.020) (\$0.020) \$0.001 \$0.001 \$0.001 (\$0.019) (\$0.019) (\$0.019) 8 9 10 Commodity Related Charges Cost of Gas (Commodity Cost Recovery Charge) per GJ \$5.962 11 \$7.536 \$7.536 \$7.536 (\$1.574) (\$1.574) (\$1.574) \$5.962 \$5.962 12 Midstream Cost Recovery Charge per GJ \$0.446 \$0.446 \$0.000 \$0.000 \$0.446 \$0.471 \$0.000 \$0.471 \$0.446 Subtotal Commodity Related Charges per GJ 13 \$8.007 \$7.982 \$7.982 (\$1.574) (\$1.574) (\$1.574) \$6.433 \$6.408 \$6.408 14 15 \$11.293 \$9.702 16 Total Variable Cost per gigajoule \$11.318 \$11.293 (\$1.616) (\$1.616) (\$1.616) \$9.677 \$9.677

TAB 5 PAGE 6 SCHEDULE 6

TAB 5 PAGE 6.1 SCHEDULE 6A

	RATE SCHEDULE 6A: NGV - VRA's			
Line No.	Particulars	EXISTING JANUARY 1, 2009 RATES	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2009 RATES
110.	(1)	(2)	(3)	(4)
1	LOWER MAINLAND SERVICE AREA			
2				
3	Delivery Margin Related Charges			
4	Basic Charge per month	\$87.00	(\$1.00)	\$86.00
5		Aa 100		
6	Delivery Charge per GJ	\$3.400	(\$0.042)	\$3.358
7	Rider 3 ESM	(\$0.110)	\$0.000	(\$0.110)
8	Rider 4 Delivery Rate Refund	(\$0.020)	\$0.001	(\$0.019)
9				
10	Commedity Delated Channes			
11 12	<u>Commodity Related Charges</u> Cost of Gas (Commodity Cost Recovery Charge) per GJ	\$7.536	(\$1.574)	\$5.962
12	Midstream Cost Recovery Charge per GJ	\$7.536 \$0.471	\$0.000	\$5.962 \$0.471
13	Subtotal Commodity Related Charges per GJ	\$8.007	(\$1.574)	\$6.433
14	Subiolal Commonly Related Charges per 65	\$6.007	(\$1.374)	φ0. 4 33
16	Compression Charge per gigajoule	\$5.28	\$0.00	\$5.28
17		4 0.20	\$0.00	40.20
18				
19	Minimum Charges	\$125.00	\$0.00	\$125.00
20		\$120.00	<i>\\</i> 0.00	ψ120.00
21				
22				
23	Total Variable Cost per gigajoule	\$16.557	(\$1.615)	\$14.942

TAB 5

PAGE 7

SCHEDULE 7

RATE SCHEDULE 7: DELIVERY MARGIN AND COMMODITY INTERRUPTIBLE SALES EXISTING JANUARY 1, 2009 RATES **RELATED CHARGES CHANGES** PROPOSED APRIL 1, 2009 RATES Line Lower Lower Lower Particulars Mainland Inland Columbia Mainland Inland Columbia Mainland Inland Columbia (3) (9) (1) (2) (4) (5) (6) (7) (8) (10) 1 Delivery Margin Related Charges Basic Charge per month \$891.00 \$891.00 \$880.00 \$880.00 2 \$891.00 (\$11.00) (\$11.00) (\$11.00) \$880.00 Delivery Charge per GJ 4 \$1.003 \$1.003 \$1.003 (\$0.013) (\$0.013) (\$0.013) \$0.990 \$0.990 \$0.990 6 Rider 3 ESM (\$0.036) (\$0.036) (\$0.036) \$0.000 \$0.000 \$0.000 (\$0.036) (\$0.036) (\$0.036) Rider 4 Delivery Rate Refund (\$0.006) \$0.006 \$0.006 \$0.006 \$0.000 \$0.000 \$0.000 7 (\$0.006) (\$0.006) Commodity Related Charges 9 Cost of Gas (Commodity Cost Recovery Charge) per GJ 10 \$7.536 \$7.536 \$7.536 (\$1.574) (\$1.574) (\$1.574) \$5.962 \$5.962 \$5.962 Midstream Cost Recovery Charge per GJ \$0.670 \$0.644 \$0.720 \$0.000 \$0.000 \$0.000 \$0.670 \$0.644 \$0.720 Subtotal Commodity Related Charges per GJ (\$1.574) \$6.632 \$6.682 \$8.206 \$8.180 \$8.256 (\$1.574) (\$1.574) \$6.606 Balancing, Backstopping and UOR per BCUC Balancing, Backstopping and UOR per BCUC 16 Charges per gigajoule for UOR Gas Order No. G-110-00. Order No. G-110-00. 22 Total Variable Cost per gigajoule \$9.167 \$9.141 \$9.217 (\$1.581) (\$1.581) (\$1.581) \$7.586 \$7.560 \$7.636

No.

3

5

8

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12

13 14 15

TAB 5 PAGE 8 SCHEDULE 22

	RATE SCHEDULE 22:					IVERY MARGIN				
	LARGE INDUSTRIAL T-SERVICE	EXISTING	JANUARY 1, 2009	RATES	RELATED	CHARGES CHA	ANGES	PROPOS	SED APRIL 1, 2009	RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	\$3,710.00	\$3,710.00	\$3,710.00	(\$46.00)	(\$46.00)	(\$46.00)	\$3,664.00	\$3,664.00	\$3,664.00
2										
3	Delivery Charge per gigajoule (Interr. MTQ)	\$0.742	\$0.742	\$0.742	(\$0.009)	(\$0.009)	(\$0.009)	\$0.733	\$0.733	\$0.733
4										
5	Rider 3 ESM	(\$0.023)	(\$0.023)	(\$0.023)	\$0.000	\$0.000	\$0.000	(\$0.023)	(\$0.023)	(\$0.023)
6	Rider 4 Delivery Rate Refund	(\$0.004)	(\$0.004)	(\$0.004)	(\$0.001)	(\$0.001)	(\$0.001)	(\$0.005)	(\$0.005)	(\$0.005)
7										
8			kstopping and UO	R per BCUC				Balancing, Back	stopping and UOF	R per BCUC
9	Charges per gigajoule for UOR Gas	Order No. G-11	10-00.					Order No. G-11	0-00.	
10										
11										
12	Demand Surcharge per gigajoule	\$17.00	\$17.00	\$17.00	\$0.00	\$0.00	\$0.00	\$17.00	\$17.00	\$17.00
13										
14										
15	Balancing Service per gigajoule									
16	(a) between and including Apr. 1 and Oct. 31	\$0.30	\$0.30	n/a	\$0.00	\$0.00	n/a	\$0.30	\$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	\$1.10	\$1.10	n/a	\$0.00	\$0.00	n/a	\$1.10	\$1.10	n/a
18										
19								Balancing Bac	kstopping and UOI	R per BCUC
20	Charges per gigajoule for Backstopping Gas		stopping and UOR	per BCUC				Order No. G-11		
21		Order No. G-110	-00.							
22										
23										
24	Administration Charge per Month	\$79.00	\$79.00	\$79.00	(\$1.00)	(\$1.00)	(\$1.00)	\$78.00	\$78.00	\$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	\$0.715	\$0.715	\$0.715	(\$0.010)	(\$0.010)	(\$0.010)	\$0.705	\$0.705	\$0.705

TAB 5 PAGE 9 SCHEDULE 22A

	RATE SCHEDULE 22A:			
	LARGE INDUSTRIAL T-SERVICE			
Line			DELIVERY MARGIN	
No.	Particulars	EXISTING JANUARY 1, 2009 RATES	RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2009 RATES
	(1)	(2)	(3)	(4)
1	INLAND SERVICE AREA			
2				
3	Basic Charge per Month	\$4,871.00	(\$61.00)	\$4,810.00
4				
5	Delivery Charge per gigajoule - Firm			
6	(a) Firm DTQ	\$11.914	(\$0.149)	\$11.765
7	(b) Firm MTQ	\$0.083	(\$0.001)	\$0.082
8				
9	Delivery Charge per gigajoule - Interr MTQ	\$0.951	(\$0.012)	\$0.939
10				
11	Rider 3 ESM	(\$0.022)	\$0.000	(\$0.022)
12	Rider 4 Delivery Rate Refund	(\$0.003)	\$0.000	(\$0.003)
13				
14		Balancing, Backstopping and UOR per BCUC		Balancing, Backstopping and UOR per BCUC
15	Charges per gigajoule for UOR Gas	Order No. G-110-00.		Order No. G-110-00.
16				
17				
18	Demand Surchage per gigajoule	\$17.00	\$0.00	\$17.00
19				
20	Balancing Service per gigajoule			
21	(a) between and including Apr. 1 and Oct. 31	\$0.30	\$0.00	\$0.30
22	(b) between and including Nov. 1 and Mar. 31	\$1.10	\$0.00	\$1.10
23				
24		Balancing, Backstopping and UOR per BCUC		Balancing, Backstopping and UOR per BCUC
25	Charges per gigajoule for Backstopping Gas	Order No. G-110-00.		Order No. G-110-00.
26				
27				
28	Replacement Gas	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	Administration Charge per Month	\$79.00	(\$1.00)	\$78.00
32				
33	Total Variable Cost per gigajoule	·	/ *	÷
34	(a) Firm MTQ	\$0.058	(\$0.001)	\$0.057
35	(b) Interruptible MTQ	\$0.926	(\$0.012)	\$0.914

TAB 5 PAGE 10 SCHEDULE 22B

	RATE SCHEDULE 22B:						
	LARGE INDUSTRIAL T-SERVICE			DELIVERY MARGIN			
		EXISTING JANUARY 1, 2009 F	RATES	RELATED CHARGES CHA	NGES	PROPOSED APRIL 1, 2009 RA	TES
Line		Columbia	Elkview	Columbia	Elkview	Columbia	Elkview
No.	Particulars	Except Elkview	Coal	Except Elkview	Coal	Except Elkview	Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	COLUMBIA SERVICE AREA						
2							
3	Basic Charge per Month	\$4,594.00	\$4,594.00	(\$57.00)	(\$57.00)	\$4,537.00	\$4,537.00
4							
5	Delivery Charge per gigajoule - Firm						
6	(a) Firm DTQ	\$7.591	\$1.724	(\$0.095)	(\$0.022)	\$7.496	\$1.702
7	(b) Firm MTQ	\$0.081	\$0.081	(\$0.001)	(\$0.001)	\$0.080	\$0.080
8							
9	Delivery Charge per gigajoule - Interr MTQ						
10	(a) between and including Apr. 1 and Oct. 31	\$0.756	\$0.189	(\$0.009)	(\$0.002)	\$0.747	\$0.187
11	(b) between and including Nov. 1 and Mar.31	\$1.090	\$0.270	(\$0.014)	(\$0.003)	\$1.076	\$0.267
12							
13	Rider 3 ESM	(\$0.018)	(\$0.007)	\$0.000	\$0.000	(\$0.018)	(\$0.007)
14	Rider 4 Delivery Rate Refund	(\$0.003)	(\$0.002)	\$0.000	(\$0.001)	(\$0.003)	(\$0.003)
15							
16		Balancing, Backstopping				Balancing, Backstopping an	
17	Charges per gigajoule for UOR Gas	BCUC Order No. G-110-	00.			BCUC Order No. G-110-00	
18							
19							
20	Demand Surchage per gigajoule	\$17.00	\$17.00	\$0.00	\$0.00	\$17.00	\$17.00
21							
22		Balancing, Backstopping a	and UOR per			Balancing, Backstopping an	
23	Charges per gigajoule for Backstopping Gas	BCUC Order No. G-110-0				BCUC Order No. G-110-00	.
24							
25							
26	Administration Charge per Month	\$79.00	\$79.00	(\$1.00)	(\$1.00)	\$78.00	\$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	\$0.060	\$0.072	(\$0.001)	(\$0.002)	\$0.059	\$0.070
31	(b) Interruptible MTQ - Summer	\$0.735	\$0.180	(\$0.009)	(\$0.003)	\$0.726	\$0.177
32	- Winter	\$1.069	\$0.261	(\$0.014)	(\$0.004)	\$1.055	\$0.257

TAB 5 PAGE 11 SCHEDULE 23

RAT	TE SCHEDULE 23:				DEL	IVERY MARGIN	I			
LAF	RGE COMMERCIAL T-SERVICE	EXISTING	JANUARY 1, 2009	RATES	RELATED	CHARGES CH	ANGES	PROPOSI	ED APRIL 1, 2009 F	RATES
ine		Lower			Lower			Lower		
lo	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	sic Charge per Month	\$134.20	\$134.20	\$134.20	(\$1.68)	(\$1.68)	(\$1.68)	\$132.52	\$132.52	\$132.52
2										
3 Deli	ivery Charge per gigajoule	\$2.163	\$2.163	\$2.163	(\$0.027)	(\$0.027)	(\$0.027)	\$2.136	\$2.136	\$2.13
4										
5										
6 Adn	ministration Charge per Month	\$79.00	\$79.00	\$79.00	(\$1.00)	(\$1.00)	(\$1.00)	\$78.00	\$78.00	\$78.00
7										
8 Sale										
9	(a) Charge per gigajoule for Balancing Gas		stopping, Replace Order No. G-110-						stopping, Replace Order No. G-110-	
10 11	(b) Charge per gigajoule for Backstopping Gas(c) Replacement Gas							UOK per BCOC	Older No. G-110-	00.
12	(d) Charge per gigajoule for UOR Gas									
12	(u) Charge per gigajoure for OOK Gas									
13 14 Rid e	er 3 ESM	(\$0.079)	(\$0.079)	(\$0.079)	\$0.000	\$0.000	\$0.000	(\$0.079)	(\$0.079)	(\$0.07
	er 4 Delivery Rate Refund	(\$0.013)	(\$0.013)	(\$0.013)	(\$0.009)	(\$0.009)	(\$0.009)	(\$0.022)	(\$0.022)	(\$0.02
	er 5 RSAM	\$0.001	\$0.001	\$0.001	\$0.000	\$0.000	\$0.000	\$0.001	\$0.001	\$0.00
17		\$0.00 I	¢0.001	\$0100 I	<i>Q</i> 0.000	<i>Q</i> (1000	<i>Q</i> 01000	Q 0.001	<i>Q</i> 0.00	φ0.0
18										
19										
	al Variable Cost per gigajoule	\$2.072	\$2.072	\$2.072	(\$0.036)	(\$0.036)	(\$0.036)	\$2.036	\$2.036	\$2.0
					<u> </u>	<u>`</u>	<u> </u>			

TAB 5 PAGE 12 SCHEDULE 25

	RATE SCHEDULE 25				DEL	IVERY MARGIN				
	GENERAL FIRM T-SERVICE	EXISTING	JANUARY 1, 2009	RATES	RELATED	CHARGES CH	ANGES	PROPOSE	ED APRIL 1, 2009 F	ATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1 2	Basic Charge per Month	\$594.00	\$594.00	\$594.00	(\$7.00)	(\$7.00)	(\$7.00)	\$587.00	\$587.00	\$587.00
3 4	Demand Charge per gigajoule	\$14.840	\$14.840	\$14.840	(\$0.185)	(\$0.185)	(\$0.185)	\$14.655	\$14.655	\$14.655
5 6	Delivery Charge per gigajoule (Interr. MTQ)	\$0.600	\$0.600	\$0.600	(\$0.007)	(\$0.007)	(\$0.007)	\$0.593	\$0.593	\$0.593
7 8	Administration Charge per Month	\$79.00	\$79.00	\$79.00	(\$1.00)	(\$1.00)	(\$1.00)	\$78.00	\$78.00	\$78.00
9 10 11 12 13 14 15	Sales (a) Charge per gigajoule for Balancing Gas (b) Charge per gigajoule for Backstopping Gas (c) Replacement Gas (d) Charge per gigajoule for UOR Gas		stopping, Replacer Order No. G-110-(stopping, Replace Order No. G-110-	
16 17 18 19 20	Rider 3 ESM Rider 4 Delivery Rate Refund	(\$0.060) (\$0.009)	(\$0.060) (\$0.009)	(\$0.060) (\$0.009)	\$0.000 (\$0.003)	\$0.000 (\$0.003)	\$0.000 (\$0.003)	(\$0.060) (\$0.012)	(\$0.060) (\$0.012)	(\$0.060) (\$0.012)
21 22	Total Variable Cost per gigajoule	\$0.531	\$0.531	\$0.531	(\$0.010)	(\$0.010)	(\$0.010)	\$0.521	\$0.521	\$0.521

TERASEN GAS INC. CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY PROPOSED APRIL 1, 2009 RATES BCUC ORDER NO. G-XXX-09

TAB 5 PAGE 13 SCHEDULE 27

	RATE SCHEDULE 27:				DEL	IVERY MARGIN				
	INTERRUPTIBLE T-SERVICE	EXISTING .	JANUARY 1, 2009 F	RATES	RELATED	CHARGES CH	ANGES	PROPOS	ED APRIL 1, 2009 F	RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	\$891.00	\$891.00	\$891.00	(\$11.00)	(\$11.00)	(\$11.00)	\$880.00	\$880.00	\$880.00
2 3										
4 5	Delivery Charge per gigajoule (Interr. MTQ)	\$1.003	\$1.003	\$1.003	(\$0.013)	(\$0.013)	(\$0.013)	\$0.990	\$0.990	\$0.990
6 7	Administration Charge per Month	\$79.00	\$79.00	\$79.00	(\$1.00)	(\$1.00)	(\$1.00)	\$78.00	\$78.00	\$78.00
8 9 10 11 12	Sales (a) Charge per gigajoule for Balancing Gas (b) Charge per gigajoule for Backstopping Gas (d) Charge per gigajoule for UOR Gas	Balancing, Back Order No. G-110	stopping and UOR I-00.	per BCUC				Balancing, Bac BCUC Order N	skstopping and UC lo. G-110-00.	R per
13 17 18 19 20	Rider 3 ESM Rider 4 Delivery Rate Refund	(\$0.036) (\$0.006)	(\$0.036) (\$0.006)	(\$0.036) (\$0.006)	\$0.000 (\$0.002)	\$0.000 (\$0.002)	\$0.000 (\$0.002)	(\$0.036) (\$0.008)	(\$0.036) (\$0.008)	(\$0.036) (\$0.008)
21 22	Total Variable Cost per gigajoule	\$0.961	\$0.961	\$0.961	(\$0.015)	(\$0.015)	(\$0.015)	\$0.946	\$0.946	\$0.946

RATE SCHEDULE 1 - RESIDENTIAL SERVICE

				RATE SCHE	DULE 1 - RESIDEN	TIAL SERVICE						
Line No.	Particular	E	EXISTING JAI	NUARY 1, 2009	RATES	PR	OPOSED	APRIL 1, 2009 R	ATES	Ir	Annual hcrease/Decrease	9
1	LOWER MAINLAND SERVICE AREA	Volu	ıme	Rate	Annual \$	Volum	e	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bil
2 3 4	Delivery Margin Related Charges Basic Charge	12	months x	\$11.99 =	\$143.88	12 m	onths x	\$11.84 =	\$142.08	(\$0.15)	(\$1.80)	-0.15%
5	Delivery Charge	95.0	GJ x	\$2.998 =		95.0	GJ x	\$2.961 =	281.2950	(\$0.037)	(3.5150)	-0.29%
6	Rider 3 ESM	95.0	GJ x	(\$0.132) =		95.0	GJ x	(\$0.132) =	(12.5400)	\$0.000	0.0000	0.00%
7	Rider 4 Delivery Rate Refund	95.0	GJ x	(\$0.022) =		95.0	GJ x	(\$0.035) =	(3.3250)	(\$0.013)	(1.2350)	-0.10%
8	Rider 5 RSAM	95.0	GJ x	\$0.001 =	0.0950	95.0	GJ x	\$0.001 =	0.0950	\$0.000	0.0000	0.00%
9 10	Subtotal Delivery Margin Related Charges				\$414.16			-	\$407.61	-	(\$6.55)	-0.53%
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	95.0	GJ x	\$0.942 =		95.0	GJ x	\$0.942 =	\$89.4900	\$0.000	\$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0	GJ x	\$0.073 =	010000	95.0	GJ x	\$0.073 =	6.9350	\$0.000	0.0000	0.00%
14 15	Midstream Related Charges Subtotal				\$96.43				\$96.43		\$0.00	0.00%
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0	GJ x	\$7.536 =	\$715.92	95.0	GJ x	\$5.962 =	\$566.39	(\$1.574)	(\$149.53)	-12.19%
17 18	Subtotal Commodity Related Charges				\$812.35			_	\$662.82	_	(\$149.53)	-12.19%
10	Total (with effective \$/GJ rate)	95.0		\$12.911	\$1,226.51	95.0		\$11.268	\$1,070.43	(\$1.643)	(\$156.08)	-12.73%
20								=	<i></i>	(*****)	(**************************************	
21	INLAND SERVICE AREA											
22	Delivery Margin Related Charges	10		0 44.00	\$110.00	10		*	\$110.00	(00.45.)	(04.00)	0.400/
23 24	Basic Charge	12	months x	\$11.99 =	\$143.88	12 m	onths x	\$11.84 =	\$142.08	(\$0.15)	(\$1.80)	-0.18%
25	Delivery Charge	75.0	GJ x	\$2.998 =	224.8500	75.0	GJ x	\$2.961 =	222.0750	(\$0.037)	(2.7750)	-0.28%
26	Rider 3 ESM	75.0	GJ x	(\$0.132) =	= (9.9000)	75.0	GJ x	(\$0.132) =	(9.9000)	\$0.000	0.0000	0.00%
27	Rider 4 Delivery Rate Refund	75.0	GJ x	(\$0.022) =	(1.6500)	75.0	GJ x	(\$0.035) =	(2.6250)	(\$0.013)	(0.9750)	-0.10%
28	Rider 5 RSAM	75.0	GJ x	\$0.001 =		75.0	GJ x	\$0.001 =	0.0750	\$0.000	0.0000	0.00%
29	Subtotal Delivery Margin Related Charges				\$357.26				\$351.71	_	(\$5.55)	-0.56%
30 31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	75.0	GJ x	\$0.903 =	\$67.7250	75.0	GJ x	\$0.903 =	\$67.7250	\$0.000	\$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0	GJ x	\$0.073 =	5.4750	75.0	GJ x	\$0.073 =	5.4750	\$0.000	0.0000	0.00%
34	Midstream Related Charges Subtotal				\$73.20			· -	\$73.20	· _	\$0.00	0.00%
35	-											
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0	GJ x	\$7.536 =	\$565.20	75.0	GJ x	\$5.962 =	\$447.15	(\$1.574)	(\$118.05)	-11.86%
37 38	Subtotal Commodity Related Charges				\$638.40			_	\$520.35	-	(\$118.05)	-11.86%
39	Total (with effective \$/GJ rate)	75.0		\$13.275	\$995.66	75.0		\$11.627	\$872.06	(\$1.648)	(\$123.60)	-12.41%
40										=		
41	COLUMBIA SERVICE AREA											
42	Delivery Margin Related Charges			6 / / 6 0	6 / / 0 00	10		• • • • • •	A 4 4 9 9 9		(0, 0, 0, 0)	a (T a)
43 44	Basic Charge	12	months x	\$11.99 =	\$143.88	12 m	onths x	\$11.84 =	\$142.08	(\$0.15)	(\$1.80)	-0.17%
44	Delivery Charge	80.0	GJ x	\$2.998 =	239.8400	80.0	GJ x	\$2.961 =	236.8800	(\$0.037)	(2.9600)	-0.28%
45	Rider 3 ESM	80.0	GJ x	(\$0.132) =		80.0	GJ x	(\$0.132) =	(10.5600)	\$0.000	0.0000	0.00%
46	Rider 4 Delivery Rate Refund	80.0	GJ x	(\$0.022) =		80.0	GJ x	(\$0.035) =	(2.8000)	(\$0.013)	(1.0400)	-0.10%
47	Rider 5 RSAM	80.0	GJ x	\$0.001 =		80.0	GJ x	\$0.001 =	0.0800	\$0.000	0.0000	0.00%
48	Subtotal Delivery Margin Related Charges				\$371.48				\$365.68	_	(\$5.80)	-0.55%
49												
50 51	Commodity Related Charges Midstream Cost Recovery Charge	80.0	GJ x	\$0.981 =	\$78.4800	80.0	GJ x	\$0.981 =	\$78.4800	\$0.000	\$0.0000	0.00%
		80.0	GJX GJX			80.0 80.0	GJX GJX					
52 53	Rider 8 Unbundling Recovery Midstream Related Charges Subtotal	0.00	GJX	\$0.073 =	5.8400 \$84.32	80.0	GJX	\$0.073 =	5.8400 \$84.32	\$0.000	0.0000 \$0.00	0.00% 0.00%
54	mastroam related charges oublotai				ΨΟΤ.ΟΖ				Ψ07.02		ψ0.00	0.0078
55	Cost of Gas (Commodity Cost Recovery Charge)	80.0	GJ x	\$7.536	\$602.88	80.0	GJ x	\$5.962 =	\$476.96	(\$1.574)	(\$125.92)	-11.89%
56	Subtotal Commodity Related Charges				\$687.20	80.0		_	\$561.28		(\$125.92)	-11.89%
57 58	Total (with effective \$/GJ rate)	80.0		\$13.234	\$1,058.68	80.0		\$11.587	\$926.96	(\$1.647)	(\$131.72)	-12.44%
90		0.00		¢13.∠34	91,0000	00.0		φ11.387 <mark>=</mark>	\$920.90	(\$1.047) =	(\$131.72)	-12.44%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

1			RA	TE SCHEDULI	E 2 -SMALL COM	IERCIAL SE	RVICE				A	
Line No.	Particular	E	EXISTING JAN	UARY 1, 2009 I	RATES	F	ROPOSED	APRIL 1, 2009 R	ATES	In	Annual crease/Decrease	9
												% of Previous
1	LOWER MAINLAND SERVICE AREA	Volu	ume	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	Total Annual Bill
2 3 4	Delivery Margin Related Charges Basic Charge	12	months x	\$25.15 =	\$301.80	12	months x	\$24.84 =	\$298.08	(\$0.31)	(\$3.72)	-0.10%
5	Delivery Charge	300.0	GJ x	\$2.510 =	753.0000	300.0	GJ x	\$2.479 =	743.7000	(\$0.031)	(9.3000)	-0.26%
6	Rider 3 ESM	300.0	GJ x	(\$0.100) =	(30.0000)	300.0	GJ x	(\$0.100) =	(30.0000)	\$0.000	0.0000	0.00%
7 8	Rider 4 Delivery Rate Refund Rider 5 RSAM	300.0 300.0	GJ x GJ x	(\$0.017) = \$0.001 =	(5.1000) 0.3000	300.0 300.0	GJ x GJ x	(\$0.029) = \$0.001 =	(8.7000) 0.3000	(\$0.012) \$0.000	(3.6000) 0.0000	-0.10% 0.00%
o 9	Subtotal Delivery Margin Related Charges	300.0	GJX	\$0.001 = <u></u>	\$1,020.00	300.0	GJX	\$0.001 = <u></u>	\$1,003.38	\$0.000	(\$16.62)	-0.47%
10 11	Commodity Related Charges			_						_		
12	Midstream Cost Recovery Charge	300.0	GJ x	\$0.947 =	\$284,1000	300.0	GJ x	\$0.947 =	\$284.1000	\$0.000	\$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0	GJ x	(\$0.021) =	(6.3000)	300.0	GJ x	(\$0.021) =	(6.3000)	\$0.000	0.0000	0.00%
14 15	Midstream Related Charges Subtotal				\$277.80			_	\$277.80	_	\$0.00	0.00%
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0	GJ x	\$7.536 =	\$2,260.80	300.0	GJ x	\$5.962 =	\$1,788.60	(\$1.574)	(\$472.20)	-13.27%
17 18	Subtotal Commodity Related Charges			-	\$2,538.60			-	\$2,066.40	-	(\$472.20)	-13.27%
19	Total (with effective \$/GJ rate)	300.0		\$11.862	\$3,558.60	300.0		\$10.233	\$3,069.78	(\$1.629)	(\$488.82)	-13.74%
20 21	INLAND SERVICE AREA											
22	Delivery Margin Related Charges											
23 24	Basic Charge	12	months x	\$25.15 =	\$301.80	12	months x	\$24.84 =	\$298.08	(\$0.31)	(\$3.72)	-0.12%
24 25	Delivery Charge	250.0	GJ x	\$2.510 =	627,5000	250.0	GJ x	\$2.479 =	619.7500	(\$0.031)	(7.7500)	-0.26%
26	Rider 3 ESM	250.0	GJ x	(\$0.100) =	(25.0000)	250.0	GJ x	(\$0.100) =	(25.0000)	\$0.000	0.0000	0.00%
27	Rider 4 Delivery Rate Refund	250.0	GJ x	(\$0.017) =	(4.2500)	250.0	GJ x	(\$0.029) =	(7.2500)	(\$0.012)	(3.0000)	-0.10%
28	Rider 5 RSAM	250.0	GJ x	\$0.001 =	0.2500	250.0	GJ x	\$0.001 =	0.2500	\$0.000	0.0000	0.00%
29 30	Subtotal Delivery Margin Related Charges			-	\$900.30			-	\$885.83	_	(\$14.47)	-0.48%
30	Commodity Related Charges											
32	Midstream Cost Recovery Charge	250.0	GJ x	\$0.907 =	\$226.7500	250.0	GJ x	\$0.907 =	\$226.7500	\$0.000	\$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0	GJ x	(\$0.021) =	(5.2500)	250.0	GJ x	(\$0.021) =	(5.2500)	\$0.000	0.0000	0.00%
34 35	Midstream Related Charges Subtotal				\$221.50				\$221.50		\$0.00	0.00%
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0	GJ x	\$7.536 =	\$1,884.00	250.0	GJ x	\$5.962 =	\$1,490.50	(\$1.574)	(\$393.50)	-13.09%
37	Subtotal Commodity Related Charges			-	\$2,105.50				\$1,712.00		(\$393.50)	-13.09%
38 39	Total (with effective \$/GJ rate)	250.0		\$12.023	\$3,005.80	250.0		\$10.391	\$2,597.83	(\$1.632)	(\$407.97)	-13.57%
40			-	=				=	,			
41	COLUMBIA SERVICE AREA											
42	Delivery Margin Related Charges	10		005 45	\$ 004.00	10		* ••••	\$ 000.00	(00.04.)	(*** *** *	0.400/
43 44	Basic Charge	12	months x	\$25.15 =	\$301.80	12	months x	\$24.84 =	\$298.08	(\$0.31)	(\$3.72)	-0.10%
45	Delivery Charge	320.0	GJ x	\$2.510 =	803.2000	320.0	GJ x	\$2.479 =	793.2800	(\$0.031)	(9.9200)	-0.26%
46	Rider 3 ESM	320.0	GJ x	(\$0.100) =	(32.0000)	320.0	GJ x	(\$0.100) =	(32.0000)	\$0.000	0.0000	0.00%
47	Rider 4 Delivery Rate Refund	320.0	GJ x	(\$0.017) =	(5.4400)	320.0	GJ x	(\$0.029) =	(9.2800)	(\$0.012)	(3.8400)	-0.10%
48	Rider 5 RSAM	320.0	GJ x	\$0.001 =	0.3200	320.0	GJ x	\$0.001 =	0.3200	\$0.000	0.0000	0.00%
49 50	Subtotal Delivery Margin Related Charges			-	\$1,067.88			-	\$1,050.40	_	(\$17.48)	-0.46%
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	320.0	GJ x	\$0.986 =	\$315.5200	320.0	GJ x	\$0.986 =	\$315.5200	\$0.000	\$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0	GJ x	(\$0.021) =	(6.7200)	320.0	GJ x	(\$0.021) =	(6.7200)	\$0.000	0.0000	0.00%
54 55	Midstream Related Charges Subtotal				\$308.80				\$308.80		\$0.00	0.00%
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0	GJ x	\$7.536 =	\$2,411.52	320.0	GJ x	\$5.962 =	\$1,907.84	(\$1.574)	(\$503.68)	-13.30%
57	Subtotal Commodity Related Charges			-	\$2,720.32			_	\$2,216.64		(\$503.68)	-13.30%
58 59	Total (with effective \$/GJ rate)	320.0		\$11.838	\$3,788.20	320.0		\$10.210	\$3,267.04	(\$1.629)	(\$521.16)	-13.76%
	. ,		-	=	,				,		,	

RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

			RA	TE SCHEDUL	E 3 - LARGE COM	IERCIAL SER	VICE					
Line <u>No.</u>	Particular	E	XISTING JA	NUARY 1, 2009	RATES	P	ROPOSED	APRIL 1, 200	9 RATES	I	Annual ncrease/Decrease	
1	LOWER MAINLAND SERVICE AREA	Volu	ime	Rate	Annual \$	Volun	ne	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bil
2 3 4	Delivery Margin Related Charges Basic Charge	12	months x	\$134.20 =	= \$1,610.40	12 r	months x	\$132.52	= \$1,590.24	(\$1.68)	(\$20.16)	-0.07%
5 6 7 8 9	Delivery Charge Rider 3 ESM Rider 4 Delivery Rate Refund Rider 5 RSAM Subtotal Delivery Margin Related Charges	2,800.0 2,800.0 2,800.0 2,800.0	GJ x GJ x GJ x GJ x	\$2.163 = (\$0.079) = (\$0.013) = \$0.001 =	= (221.2000)	2,800.0 2,800.0 2,800.0 2,800.0	GJ x GJ x GJ x GJ x	\$2.136 (\$0.079) (\$0.021) \$0.001	= (221.2000)	(\$0.027) \$0.000 (\$0.008) \$0.000	(75.6000) 0.0000 (22.4000) 0.0000 (\$118.16)	-0.25% 0.00% -0.07% 0.00% -0.38%
10 11 12 13 14 15	Commodity Related Charges Midstream Cost Recovery Charge Rider 8 Unbundling Recovery Midstream Related Charges Subtotal	2,800.0 2,800.0	GJ x GJ x	\$0.830 = (\$0.021) =	φ2,02 110000	2,800.0 2,800.0	GJ x GJ x	\$0.830 (\$0.021)	= \$2,324.0000 = (58.8000) \$2,265.20	\$0.000 \$0.000 _	\$0.0000 0.0000 \$0.00	0.00% 0.00% 0.00%
16 17	Cost of Gas (Commodity Cost Recovery Charge) Subtotal Commodity Related Charges	2,800.0	GJ x	\$7.536 =	= \$21,100.80 \$23,366.00	2,800.0	GJ x	\$5.962	= \$16,693.60 \$18,958.80	(\$1.574)	(\$4,407.20) (\$4,407.20)	-14.32% -14.32%
18 19 20	Total (with effective \$/GJ rate)	2,800.0		\$10.992	\$30,778.00	2,800.0		\$9.376	\$26,252.64	(\$1.616)	(\$4,525.36)	-14.70%
21 22 23 24	INLAND SERVICE AREA Delivery Margin Related Charges Basic Charge	12	months x	\$134.20 =	= \$1,610.40	12 r	nonths x	\$132.52	= \$1,590.24	(\$1.68)	(\$20.16)	-0.07%
25 26 27 28 29	Delivery Charge Rider 3 ESM Rider 4 Delivery Rate Refund Rider 5 RSAM Subtotal Delivery Margin Related Charges	2,600.0 2,600.0 2,600.0 2,600.0	GJ x GJ x GJ x GJ x	\$2.163 = (\$0.079) = (\$0.013) = \$0.001 =	= (205.4000) = (33.8000)	2,600.0 2,600.0 2,600.0 2,600.0	GJ x GJ x GJ x GJ x	\$2.136 (\$0.079) (\$0.021) \$0.001	= (205.4000)	(\$0.027) \$0.000 (\$0.008) \$0.000	(70.2000) 0.0000 (20.8000) 0.0000 (\$111.16)	-0.25% 0.00% -0.07% 0.00% -0.39%
30 31 32 33 34	Commodity Related Charges Midstream Cost Recovery Charge Rider 8 Unbundling Recovery Midstream Related Charges Subtotal	2,600.0 2,600.0	GJ x GJ x	\$0.796 = (\$0.021) =		2,600.0 2,600.0	GJ x GJ x	\$0.796 (\$0.021)	• ,	\$0.000 \$0.000 _	\$0.0000 0.0000 \$0.00	0.00% 0.00% 0.00%
35 36 37	Cost of Gas (Commodity Cost Recovery Charge) Subtotal Commodity Related Charges	2,600.0	GJ x	\$7.536 =	\$19,593.60 \$21,608.60	2,600.0	GJ x	\$5.962	= \$15,501.20 \$17,516.20	(\$1.574)	(\$4,092.40) (\$4,092.40)	-14.31% -14.31%
38 39 40	Total (with effective \$/GJ rate)	2,600.0		\$11.002	\$28,606.20	2,600.0		\$9.386	\$24,402.64	(\$1.617)	(\$4,203.56)	-14.69%
41 42 43 44	COLUMBIA SERVICE AREA Delivery Margin Related Charges Basic Charge	12	months x	\$134.20 =	= \$1,610.40	12 r	nonths x	\$132.52	= \$1,590.24	(\$1.68)	(\$20.16)	-0.06%
45 46 47 48 49	Delivery Charge Rider 3 ESM Rider 4 Delivery Rate Refund Rider 5 RSAM Subtotal Delivery Margin Related Charges	3,300.0 3,300.0 3,300.0 3,300.0	GJ x GJ x GJ x GJ x	\$2.163 = (\$0.079) = (\$0.013) = \$0.001 =	= (260.7000) = (42.9000)	3,300.0 3,300.0 3,300.0 3,300.0	GJ x GJ x GJ x GJ x	\$2.136 (\$0.079) (\$0.021) \$0.001	= (260.7000) = (69.3000)	(\$0.027) \$0.000 (\$0.008) \$0.000	(89.1000) 0.0000 (26.4000) 0.0000 (\$135.66)	-0.25% 0.00% -0.07% 0.00% -0.38%
50 51 52 53 54 55	<u>Commodity Related Charges</u> Midstream Cost Recovery Charge Rider 8 Unbundling Recovery Midstream Related Charges Subtotal	3,300.0 3,300.0	GJ x GJ x	\$0.873 = (\$0.021) =		3,300.0 3,300.0	GJ x GJ x	\$0.873 (\$0.021)	• ,	\$0.000 \$0.000 _	\$0.0000 0.0000 \$0.00	0.00% 0.00% 0.00%
56 57	Cost of Gas (Commodity Cost Recovery Charge) Subtotal Commodity Related Charges	3,300.0	GJ x	\$7.536 =	\$24,868.80 \$27,680.40	3,300.0	GJ x	\$5.962	= \$19,674.60 \$22,486.20	(\$1.574)	(\$5,194.20) (\$5,194.20)	-14.38% -14.38%
58 59	Total (with effective \$/GJ rate)	3,300.0		\$10.948	\$36,128.40	3,300.0		\$9.333	\$30,798.54	(\$1.615)	(\$5,329.86)	-14.75%

RATE SCHEDULE 4 - SEASONAL SERVICE

			RATE S	CHEDULE 4	- SEASONAL	SERVICE						
Line											Annual	
No.	Particular	E	XISTING JAI	NUARY 1, 200	9 RATES		PROPOSED	D APRIL 1, 200	9 RATES		Increase/Decrease	
		.,,										% of Previous
1		Volu	ime	Rate	Annual \$	_	olume	Rate	Annual \$	Rate	Annual \$	Total Annual Bil
	LOWER MAINLAND SERVICE AREA											
3	Delivery Margin Related Charges											
4	Basic Charge	7	months x	\$445.00	= \$3,115.00		7 months x	\$439.00	= \$3,073.00	(\$6.00)	(\$42.00)	-0.08%
5												
6	Delivery Charge											
7	(a) Off-Peak Period	5,400.0	GJ x	\$0.772	,	,			,	(\$0.010)	(54.0000)	-0.11%
8	(b) Extension Period	0.0	GJ x	\$1.558						(\$0.019)	0.0000	0.00%
9	Rider 3 ESM	5,400.0	GJ x	(\$0.061)	· · ·	, ,		(.)	```	\$0.000	0.0000	0.00%
10	Rider 4 Delivery Rate Refund	5,400.0	GJ x	(\$0.006)			0 GJ x	(\$0.001)		\$0.005	27.0000	0.05%
11	Subtotal Delivery Margin Related Charges				\$6,922.00				\$6,853.00		(\$69.00)	-0.13%
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge	=	<u>.</u>	A a a a				••••	AA A A A A A A A A 	AA AAA	••••••	0.000/
15	(a) Off-Peak Period	5,400.0	GJ x	\$0.670		,				\$0.000	\$0.0000	0.00%
16	(b) Extension Period	0.0	GJ x	\$0.670	= 0.00	0 00	0 GJ x	\$0.670	= 0.0000	\$0.000	0.0000	0.00%
17	Commodity Cost Recovery Charge	F 400 0	<u></u>	A7 500	10 00 1 1	5 400	<u> </u>	* = 000	00 40 4 0000	(04 57 4)	(0, 400, 0000)	10 500/
18	(a) Off-Peak Period	5,400.0	GJ x	\$7.536		,			,	(\$1.574)	(8,499.6000)	-16.59%
19	(b) Extension Period	0.0	GJ x	\$7.536	= 0.00	0 00	0 GJ x	\$5.962	= 0.0000	(\$1.574)	0.0000	0.00%
20					<u> </u>							
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				\$44,312.40				\$35,812.80		(\$8,499.60)	-16.59%
22												
23	Unauthorized Gas Charge During Peak Period (not forecast)											
24	Total during Off-Peak Period	5,400.0			¢E4 004 44	E 400	0		\$42,665.80		(\$0 EC0 C0)	-16.72%
	Total during Oil-Peak Pendu	5,400.0			\$51,234.40	5,400	0		\$42,005.80		(\$8,568.60)	-10.72%
26 27												
27	INLAND SERVICE AREA											
28 29	Delivery Margin Related Charges											
29 30	Basic Charge	7	months x	¢445.00	= \$3,115.00		7 months x	¢420.00	= \$3,073.00	(\$6.00.)	(\$42.00)	-0.05%
30	Basic Charge	1	monuns x	\$445.00	= \$3,115.00		/ monuns x	\$439.00	= \$3,073.00	(\$6.00)	(\$42.00)	-0.05%
32	Delivery Charge											
33	(a) Off-Peak Period	9,300.0	GJ x	\$0.772	= 7,179.60	9,300	0 GJ x	\$0.762	= 7,086.6000	(\$0.010)	(93.0000)	-0.11%
33	(a) On-reak renou (b) Extension Period	9,300.0	GJX	\$1.558	,					(\$0.010)	0.0000	0.00%
35	Rider 3 ESM	9,300.0	GJX	(\$0.061)						\$0.000	0.0000	0.00%
36	Rider 4 Delivery Rate Refund	9,300.0	GJX	(\$0.001)						\$0.005	46.5000	0.05%
37	Subtotal Delivery Margin Related Charges	5,500.0	00 1	(\$0.000)	\$9,671.50		0 00 1	(\$0.001)	\$9,583.00	ψ0.005	(\$88.50)	-0.10%
38	Subtotal Delivery Margin Related Charges				ψ3,071.30				ψ3,303.00		(#00.50)	-0.1070
39	Commodity Related Charges											
40	Midstream Cost Recovery Charge											
41	(a) Off-Peak Period	9,300.0	GJ x	\$0.644	= \$5,989.20	9,300	0 GJ x	\$0.644	= \$5,989.2000	\$0.000	\$0.0000	0.00%
42	(b) Extension Period	0.0	GJ x	\$0.644		,				\$0.000	0.0000	0.00%
43	Commodity Cost Recovery Charge	0.0		φ0.044	- 0.00			φ0.011	- 0.0000	φ0.000	0.0000	0.0070
44	(a) Off-Peak Period	9,300.0	GJ x	\$7.536	= 70,084.80	9,300	0 GJ x	\$5.962	= 55,446.6000	(\$1.574)	(14,638.2000)	-17.07%
45	(b) Extension Period	0.0	GJ x		= 70,004.00					(\$1.574)	0.0000	0.00%
46		0.0	00 /	<i>Q1</i> 000	0.00		0 00 A	\$0.00 <u>2</u>	0.0000	(\$	0.0000	0.0070
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				\$76,074.00				\$61,435.80		(\$14,638.20)	-17.07%
48					<u> </u>	—					(+,000.20)	
49	Unauthorized Gas Charge During Peak Period (not forecast)											
50												
	Total during Off-Peak Period	9,300.0			\$85.745.50	9,300	0		\$71.018.80		(\$14,726.70)	-17.17%
	y	.,							. ,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	1		

RATE SCHEDULE 5 -GENERAL FIRM SERVICE

$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	% of Previous Total Annual \$ (\$84.00) -0.08% (\$125.65) -0.12% (\$67.9000) -0.07% 0.0000 0.00% (\$155.20) -0.15% \$0.0000 0.00% (\$15,267.8000) -14.97% 15,267.80 -14.97%
$\begin{array}{c c c c c c c c c c c c c c c c c c c $	(\$125.65) -0.12% (\$67.9000) -0.07% 0.0000 0.00% (\$155.20) -0.15% \$0.0000 0.00% (\$15.267.8000) -14.97%
4 Basic Charge 12 months x \$\$594.00 = \$7,128.00 12 months x \$\$587.00 = \$7,044.00 (\$7,00) [\$5,00] 6 Demand Charge 56.6 GJ x \$14.840 = \$10,079.33 56.6 GJ x \$14.655 = \$9,953.68 (\$0.018) [\$0,079.33] \$56.6 GJ x \$14.655 = \$9,953.68 (\$0.000) [\$0,000] \$\$0.000 \$0,700.0 GJ x \$0.503 = \$5,752.1000 \$0,000 \$0.50.00 \$0.000 \$0.611	(\$125.65) -0.12% (\$67.9000) -0.07% 0.0000 0.00% (\$155.20) -0.15% \$0.0000 0.00% (\$15.267.8000) -14.97%
6 Demand Charge 56.6 GJ x \$14.840 $=$ \$10,079.33 56.6 GJ x \$14.655 $=$ \$9,953.68 (\$0.185) 7 Delivery Charge 9,700.0 GJ x \$0.600 $=$ \$5,820.000 9,700.0 GJ x \$0.600 $=$ \$5,150.70 $=$ \$4,995.50 \$0.000	(\$67.9000) -0.07% 0.0000 0.00% (\$155.20) -0.15% \$0.0000 0.00% (\$15,267.8000) -14.97%
9 Rider 3 ESM 9,700.0 GJ x (\$0.060) = (\$582.000) 9,700.0 GJ x (\$0.060) = (\$582.000) 9,700.0 GJ x (\$0.009) = (\$7.300) 9,700.0 GJ x (\$0.009) = (\$7.300) 9,700.0 GJ x (\$0.009) = (\$0.009) <t< td=""><td>0.0000 0.00% (87.3000) -0.09% (\$155.20) -0.15% \$0.0000 0.00% (5,267.8000) -14.97%</td></t<>	0.0000 0.00% (87.3000) -0.09% (\$155.20) -0.15% \$0.0000 0.00% (5,267.8000) -14.97%
10 Rider 4 Delivery Rate Refund 9,700.0 GJ x $(\$0.009) = (\$7.3000)$ 9,700.0 GJ x $(\$0.009) = (\$7.3000)$ 9,700.0 GJ x $(\$0.009) = (\$7.3000)$ $\$4,995.50$ (\\$0.009) (\\$0.009) 1 12 Commodity Related Charges 9,700.0 GJ x $\$0.670 = \$6,499.0000$ 9,700.0 GJ x $\$0.670 = \$6,499.0000$ $\$0.000$	(87.3000) -0.09% (\$155.20) -0.15% \$0.0000 0.00% 15,267.8000) -14.97%
11 Subtotal Delivery Margin Related Charges 12 $$$5,150.70$ 13 Commodity Related Charges 14 Midstream Cost Recovery Charge 15 Commodity Cost Recovery Charge 16 Subtotal Gas Commodity Cost (commodity Related Charge) 17 $$79,598.20$ 18 Total (with effective \$/GJ rate) 9 $$700.0$ 9 $$10.511$ 19 INLAND SERVICE AREA 10 INLAND SERVICE AREA 12 months x \$594.00 13 GJ x \$14.655 14 GJ x \$14.655 15 (\$1.612) 16 S11 17 S11 18 S11	(\$155.20) -0.15% \$0.0000 0.00% 15,267.8000) -14.97%
$\begin{array}{c c c c c c c c c c c c c c c c c c c $	\$0.0000 0.00% [5,267.8000] -14.97%
14 Midstream Cost Recovery Charge 9,700.0 GJ x \$0.670 = \$6,499.0000 9,700.0 GJ x \$0.670 = \$6,499.0000 \$0.000 15 Commodity Cost Recovery Charge 9,700.0 GJ x \$7.536 = 73,099.2000 $9,700.0$ GJ x \$5.962 = 57,831.4000 \$0.000 \$1.574) (1 16 Subtotal Gas Commodity Cost (Commodity Related Charge) 9,700.0 \$10.511 \$101,956.23 9,700.0 \$8.899 \$86,323.58 (\$1.612)	-14.97%
15 Commodity Cost Recovery Charge 9,700.0 GJ x $\$7.536$ = $73,099,2000$ $\$70.0$ GJ x $\$5.962$ = $57,831.4000$ ($\$1.574$) ($\1.674) ($\$1.674$) ($\1.674) ($\$1.674$) ($\1.674) ($\$1.674$) ($\1.674) ($\$1.674$) ($\1.674) ($\$1.612$) ($\1.612) ($\$1.612$) ($\1.612) ($\$1.612$) ($\1.612) ($\$1.612$) ($\1.612 ($\$1.612$) ($\1.612 ($\$1.612$) ($\1.612) ($\$1.612$ ($\$1.612$) ($\1.612 ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ ($\$1.612$ <td< td=""><td>-14.97%</td></td<>	-14.97%
16 Subtotal Gas Commodity Cost (Commodity Related Charge) \$79,598.20 \$64,330.40 (\$1 17 18 Total (with effective \$/GJ rate) $9,700.0$ \$10.511 \$101,956.23 $9,700.0$ \$8.899 \$86,323.58 (\$1.612) (\$1 19 INLAND SERVICE AREA $9,700.0$ \$10.511 \$101,956.23 $9,700.0$ \$8.899 \$86,323.58 (\$1.612) (\$1 19 INLAND SERVICE AREA 12 months x \$594.00 = \$7,128.00 12 months x \$587.00 = \$7,044.00 (\$7.00) \$ 23 Basic Charge 81.1 GJ x \$14.840 = \$14,442.29 81.1 GJ x \$14.655 \$14,262.25 (\$0.085) \$ 26 Delivery Charge 12,800.0 GJ x \$0.600 \$7,680.0000 12,800.0 GJ x \$0.693 \$7,590.4000 \$<	
17 18 Total (with effective \$/GJ rate) 9,700.0 \$10.511 \$101,956.23 9,700.0 \$88,899 \$86,323.58 (\$1.612)<	5.267.80) -14.97%
18 Total (with effective \$/GJ rate) 9,700.0 \$10.511 \$101,956.23 9,700.0 \$88.899 \$86,323.58 (\$1.612) (\$1 19 INLAND SERVICE AREA Intervent Margin Related Charges 12 months x \$594.00 = \$7,128.00 12 months x \$587.00 = \$7,044.00 (\$7.00)	<u>.,,</u>
19 20 INLAND SERVICE AREA 21 Delivery Margin Related Charges 22 Basic Charge 23 24 24 Demand Charge 25 81.1 26 Delivery Charge 27 Rider 3 28 Rider 4 29 Rider 4 20 Delivery Rate Refund 12 months x 5 5 26 Delivery Charge 12,800.0 GJ x 5 12,800.0 6 12,800.0 6 12,800.0 7 Rider 3 20 12,800.0 21 12,800.0 22 23.4000 23 12,800.0 24 Delivery Rate Refund 12,800.0 GJ x 26 12,800.0 27 Rider 4 28 Rider 4 29 12,800.0 20 GJ x 21 12,800.0 22 23.4000	15,632.65) -15.33%
21 Delivery Margin Related Charges 22 Basic Charge 12 months x \$594.00 = \$7,128.00 12 months x \$587.00 = \$7,044.00 (\$7.00)	<u> </u>
22 Basic Charge 12 months x \$594.00 = \$7,128.00 12 months x \$587.00 = \$7,044.00 (\$7.00) 23 24 Demand Charge 81.1 GJ x \$14.840 = \$14,442.29 81.1 GJ x \$14.655 = \$14,262.25 (\$0.185) 25 26 Delivery Charge 12,800.0 GJ x \$0.600 = \$7,680.0000 12,800.0 GJ x \$0.600) = \$7,590.4000 (\$0.007) 27 Rider 3 ESM 12,800.0 GJ x (\$0.060) = (768.0000) 12,800.0 GJ x \$0.000) \$0.000 28 Rider 4 Delivery Rate Refund 12,800.0 GJ x (\$0.009) = (115.2000) 12,800.0 GJ x (\$0.018) = (230.4000) (\$0.009)	
23 24 Demand Charge 81.1 GJ x \$14.840 = \$14,442.29 81.1 GJ x \$14.655 = \$14,262.25 (\$0.185) 25 26 Delivery Charge 12,800.0 GJ x \$0.600 = \$7,680.0000 12,800.0 GJ x \$0.593 = \$7,590.4000 (\$0.007) 27 Rider 3 ESM 12,800.0 GJ x (\$0.060) = (768.0000) 12,800.0 GJ x (\$0.060) = (768.0000) \$0.000 28 Rider 4 Delivery Rate Refund 12,800.0 GJ x (\$0.018) = (230.4000) (\$0.009)	
24 Demand Charge 81.1 GJ x \$14.840 = \$14,442.29 81.1 GJ x \$14.655 = \$14,262.25 (\$0.185) 25 26 Delivery Charge 12,800.0 GJ x \$0.600 = \$7,680.0000 12,800.0 GJ x \$0.593 = \$7,590.4000 (\$0.007) 27 Rider 3 ESM 12,800.0 GJ x \$0.609 = (768.0000) 12,800.0 GJ x \$0.000 \$0.000 28 Rider 4 Delivery Rate Refund 12,800.0 GJ x \$0.009 = (115.2000) 12,800.0 GJ x \$0.018) = (230.4000) \$0.009	(\$84.00) -0.06%
25 26 Delivery Charge 12,800.0 GJ x \$0.600 = \$7,680.0000 12,800.0 GJ x \$0.593 = \$7,590.4000 (\$0.007) 27 Rider 3 ESM 12,800.0 GJ x (\$0.060) = (768.0000) 12,800.0 GJ x (\$0.060) = (\$0.000) \$0.000 28 Rider 4 Delivery Rate Refund 12,800.0 GJ x (\$0.009) = (115.2000) 12,800.0 GJ x (\$0.018) = (230.4000) (\$0.009)	
26 Delivery Charge 12,800.0 GJ x \$0.600 = \$7,680.0000 12,800.0 GJ x \$0.593 = \$7,590.4000 (\$0.007) 27 Rider 3 ESM 12,800.0 GJ x (\$0.600) = (768.0000) 12,800.0 GJ x (\$0.007) 28 Rider 4 Delivery Rate Refund 12,800.0 GJ x (\$0.009) = (115.2000) 12,800.0 GJ x (\$0.018) = (230.4000) (\$0.009)	(\$180.04) -0.14%
27 Rider 3 ESM 12,800.0 GJ x (\$0.060) = (768.0000) 12,800.0 GJ x (\$0.060) = (768.0000) \$0.000 28 Rider 4 Delivery Rate Refund 12,800.0 GJ x (\$0.009) = (115.2000) 12,800.0 GJ x (\$0.018) = (230.4000) (\$0.009)	(\$90,6000) 0.07%
28 Rider 4 Delivery Rate Refund 12,800.0 GJ x (\$0.009) = (115.2000) 12,800.0 GJ x (\$0.018) = (230.4000) (\$0.009)	(\$89.6000) -0.07% 0.0000 0.00%
	(115.2000) -0.09%
29 Subtotal Delivery Margin Related Charges \$6,796.80 \$6,592.00	(\$204.80) -0.15%
	(#204.00)
31 Commodity Related Charges	
32 Midstream Cost Recovery Charge 12,800.0 GJ x \$0.644 = \$8,243.2000 12,800.0 GJ x \$0.644 = \$8,243.2000 \$0.000	\$0.0000 0.00%
	20,147.2000) -15.14%
	20,147.20) -15.14%
35	<u> </u>
36 Total (with effective \$/GJ rate) 12,800.0 \$10.396 \$133,071.09 12,800.0 \$8.786 \$112,455.05 (\$1.611) \$\$2	20,616.04) -15.49%
37	
38 COLUMBIA SERVICE AREA	
39 Delivery Margin Related Charges	
40 Basic Charge 12 months x \$594.00 = \$7,128.00 12 months x \$587.00 = \$7,044.00 (\$7.00)	(\$84.00) -0.09%
41 42 Demand Charge 62.0 GJ x \$14.840 = \$11,040.96 62.0 GJ x \$14.655 = \$10,903.32 (\$0.185)	(\$137.64) -0.14%
42 Demand Charge 62.0 GJ x \$14.840 = \$11,040.96 62.0 GJ x \$14.655 = \$10,903.32 (\$0.185) 43	(\$137.64) -0.14%
43 44 Delivery Charge 9,100.0 GJ x \$0.600 = \$5,460.0000 9,100.0 GJ x \$0.593 = \$5,396.3000 (\$0.007)	(\$63.7000) -0.06%
45 Rider 3 ESM 9,100.0 GJ x (\$0.060) = (546.0000) 9,100.0 GJ x (\$0.060) = (546.0000) (\$0.000)	0.0000 0.00%
46 Rider 4 Delivery Rate Refund 9,100.0 GJ x (\$0.009) = (81.9000) 9,100.0 GJ x (\$0.018) = (163.8000) (\$0.009)	(81.9000) -0.08%
47 Subtal Delivery Margin Related Charges \$4,832.10 \$4,686.50	(\$145.60) -0.15%
48	<u>. </u>
49 Commodity Related Charges	
50 Midstream Cost Recovery Charge 9,100.0 GJ x \$0.720 = \$6,552.0000 9,100.0 GJ x \$0.720 = \$6,552.0000 \$0.000	\$0.0000 0.00%
	-14.60%
	14,323.40) -14.60%
54 Total (with effective \$/GJ rate) 9,100.0 \$10.784 \$98,130.66 9,100.0 \$9.169 \$83,440.02 (\$1.614) (\$1.614)	14,690.64) -14.97%

RATE SCHEDULE 6 - NGV - STATIONS

				RATE SCH	IEDULE 6 - NGV -	STATIONS						
Line	Particular	-		IUARY 1, 2009		-		APRIL 1, 2009			Annual Increase/Decrease	
No.	Particular	E	XISTING JAN	UART 1, 2009	RATES	г Р	RUPUSED	APRIL 1, 2009	RATES		increase/Decrease	
1		Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bil
2	LOWER MAINLAND SERVICE AREA											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	\$62.00 =	\$744.00	12	months x	\$61.00 =	\$732.00	(\$1.00)	(\$12.00)	-0.04%
5	-											
6	Delivery Charge	2,900.0	GJ x	\$3.441 =	9,978.9000	2,900.0	GJ x	\$3.398 =	9,854.2000	(\$0.043)	(124.7000)	-0.37%
7	Rider 3 ESM	2,900.0	GJ x	(\$0.110) =	(319.0000)	2,900.0	GJ x	(\$0.110) =	(319.0000)	\$0.000	0.0000	0.00%
8	Rider 4 Delivery Rate Refund	2,900.0	GJ x	(\$0.020) =	(58.0000)	2,900.0	GJ x	(\$0.019) =	(55.1000)	\$0.001	2.9000	0.01%
9	Subtotal Delivery Margin Related Charges			_	\$10,345.90			-	\$10,212.10	_	(\$133.80)	-0.40%
10				_				-		_		
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	2,900.0	GJ x	\$0.471 =	\$1,365.9000	2,900.0	GJ x	\$0.471 =	\$1,365.9000	\$0.000	\$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0	GJ x	\$7.536 =	21,854.4000	2,900.0	GJ x	\$5.962 =	17,289.8000	(\$1.574)	(4,564.6000)	-13.60%
14	Subtotal Cost of Gas (Commodity Related Charge)				\$23,220.30				\$18,655.70		(\$4,564.60)	-13.60%
15				_				_				
16	Total (with effective \$/GJ rate)	2,900.0		\$11.575	\$33,566.20	2,900.0		\$9.954	\$28,867.80	(\$1.620)	(\$4,698.40)	-14.00%
17				-				-		_		
18												
19	INLAND SERVICE AREA											
20	Delivery Margin Related Charges											
21	Basic Charge	12	months x	\$62.00 =	\$744.00	12	months x	\$61.00 =	\$732.00	(\$1.00)	(\$12.00)	-0.01%
22												
23	Delivery Charge	11,900.0	GJ x	\$3.441 =	40,947.9000	11,900.0	GJ x	\$3.398 =	-,	(\$0.043)	(511.7000)	-0.38%
24	Rider 3 ESM	11,900.0	GJ x	(\$0.110) =	(1,309.0000)	11,900.0	GJ x	(\$0.110) =	()	\$0.000	0.0000	0.00%
25	Rider 4 Delivery Rate Refund	11,900.0	GJ x	(\$0.020) =	(238.0000)	11,900.0	GJ x	(\$0.019) =		\$0.001	11.9000	0.01%
	Subtotal Delivery Margin Related Charges			-	\$40,144.90			-	\$39,633.10	_	(\$511.80)	-0.38%
27												
	Commodity Related Charges											
29	Midstream Cost Recovery Charge	11,900.0	GJ x	\$0.446 =	\$5,307.4000	11,900.0	GJ x	\$0.446 =	+ - /	\$0.000	\$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0	GJ x	\$7.536 =	89,678.4000	11,900.0	GJ x	\$5.962 =		(\$1.574)	(18,730.6000)	-13.86%
	Subtotal Cost of Gas (Commodity Related Charge)			-	\$94,985.80			-	\$76,255.20	_	(\$18,730.60)	-13.86%
32												
33	Total (with effective \$/GJ rate)	11,900.0		\$11.356 -	\$135,130.70	11,900.0		\$9.739 -	\$115,888.30	(\$1.617)	(\$19,242.40)	-14.24%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

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RATE SCHEDULE 7 - INTERRUPTIBLE SALES

			RATES	CHEDULE 7	- INTERRUPTIBLE S	SALES						
Line No.	Particular	E	EXISTING JAI	NUARY 1, 200	9 RATES	PR	OPOSED	APRIL 1, 2009	RATES	l	Annual Increase/Decrease	e
												% of Previous
1		Volu	ume	Rate	Annual \$	Volum	е	Rate	Annual \$	Rate	Annual \$	Annual Bil
2	LOWER MAINLAND SERVICE AREA											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	\$891.00	= \$10,692.00	12 ma	onths x	\$880.00 =	\$10,560.00	(\$11.00)	(\$132.00)	-0.16%
5	·											
6	Delivery Charge	8,100.0	GJ x	\$1.003	= \$8,124.3000	8,100.0	GJ x	\$0.990 =	\$8,019.0000	(\$0.013)	(\$105.3000)	-0.12%
7	Rider 3 ESM	8,100.0	GJ x	(\$0.036)	= (291.6000)	8,100.0	GJ x	(\$0.036) =	(291.6000)	\$0.000	0.0000	0.00%
8	Rider 4 Delivery Rate Refund	8,100.0	GJ x	(\$0.006)	= (48.6000)	8,100.0	GJ x	\$0.000 =	0.0000	\$0.006	48.6000	0.06%
9	Subtotal Delivery Margin Related Charges				\$7,784.10				\$7,727.40	_	(\$56.70)	-0.07%
10										-		
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	8,100.0	GJ x	\$0.670	= \$5,427.0000	8,100.0	GJ x	\$0.670 =	\$5,427.0000	\$0.000	\$0.0000	0.00%
13	Commodity Cost Recovery Charge	8,100.0	GJ x	\$7.536	= 61,041.6000	8,100.0	GJ x	\$5.962 =	48,292.2000	(\$1.574)	(12,749.4000)	-15.01%
14	Subtotal Gas Sales - Fixed (Commodity Related Charge)				\$66,468.60				\$53,719.20		(\$12,749.40)	-15.01%
15										_		
16	Non-Standard Charges (not forecast)											
17	Index Pricing Option, UOR											
18												
19	Total (with effective \$/GJ rate)	8,100.0		\$10.487	\$84,944.70	8,100.0		\$8.890	\$72,006.60	(\$1.597)	(\$12,938.10)	-15.23%
20										-		
21												
22	INLAND SERVICE AREA											
23	Delivery Margin Related Charges											
24	Basic Charge	12	months x	\$891.00	= \$10,692.00	12 ma	onths x	\$880.00 =	\$10,560.00	(\$11.00)	(\$132.00)	-0.28%
25												
26	Delivery Charge	4,000.0	GJ x	\$1.003	• , • • • • • •	4,000.0	GJ x	\$0.990 =		(\$0.013)	(\$52.0000)	-0.11%
27	Rider 3 ESM	4,000.0	GJ x	(\$0.036)		4,000.0	GJ x	(\$0.036) =		\$0.000	0.0000	0.00%
28	Rider 4 Delivery Rate Refund	4,000.0	GJ x	(\$0.006)		4,000.0	GJ x	\$0.000 =		\$0.006	24.0000	0.05%
29	Subtotal Delivery Margin Related Charges				\$3,844.00				\$3,816.00	_	(\$28.00)	-0.06%
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	4,000.0	GJ x	+	= \$2,576.0000	4,000.0	GJ x	\$0.644 =	• /	\$0.000	\$0.0000	0.00%
33	Commodity Cost Recovery Charge	4,000.0	GJ x	\$7.536		4,000.0	GJ x	\$5.962 =		(\$1.574)	(6,296.0000)	-13.32%
34	Subtotal Gas Sales - Fixed (Commodity Related Charge)				\$32,720.00				\$26,424.00	_	(\$6,296.00)	-13.32%
35												
	Non-Standard Charges (not forecast)											
37	Index Pricing Option, UOR											
38	Tatal (with affective @/O I rate)	4 000 0		.	A 47 050 05	4 000 0		A / A A A A	* 40,000,00	(0.1.0.1.1)	(*** 45*****	40.000/
39	Total (with effective \$/GJ rate)	4,000.0		\$11.814	\$47,256.00	4,000.0		\$10.200	\$40,800.00	(\$1.614)	(\$6,456.00)	-13.66%

RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

			•			•••••••••••						
Line No.	Particular		EXISTING JA	NUARY 1, 2009	RATES	F	PROPOSED	APRIL 1, 2009 RA	TES	Inc	Annual crease/Decrease	
1		Volu	me	Rate	Annual \$	Volun	ne	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bil
2	LOWER MAINLAND SERVICE AREA											
3	Basic Charge	12	months x	\$3,710.00	= \$44,520.00	12	months x	\$3,664.00 =	\$43,968.00	(\$46.00)	(\$552.00)	-0.16%
4	-											
6	Delivery Charge - Interruptible MTQ	422,966.3	GJ x	\$0.742	= \$313,840.9946	422,966.3	GJ x	\$0.733 =	\$310,034.2979	(\$0.009)	(\$3,806.6967)	-1.09%
7	Rider 3 ESM	422,966.3	GJ x			422,966.3	GJ x	(\$0.023) =	(9,728.2249)	\$0.000	0.0000	0.00%
8	Rider 4 Delivery Rate Refund	422,966.3	GJ x	(\$0.004)	= (1,691.8652)	422,966.3	GJ x	(\$0.005) =	(2,114.8315)	(\$0.001)	(422.9663)	-0.12%
9	Transportation - Interruptible			, ,	\$302,420.90				\$298,191.24		(\$4,229.66)	-1.22%
10												
11												
12	Non-Standard Charges (not forecast)											
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
14												
15												
16	Administration Charge	12	months x	\$79.00	= \$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	0.00%
17												
18												
19	Total (with effective \$/GJ rate)	422,966.3		\$0.822	\$347,888.90	422,966.3		\$0.811	\$343,095.24	(\$0.011)	(\$4,793.66)	-1.38%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line <u>No.</u> Particular	EXISTING	JANUARY 1, 2009			APRIL 1, 2009 RATES		Annual se/Decrease
1	Volume	Rate	Annual \$	Volume	Rate Annual \$	Rate A	% of Previous nnual \$ Annual Bil
2 INLAND SERVICE AREA 3 Basic Charge 4	12 months	x \$4,871.00	= \$58,452.00	12 months x	\$4,810.00 = \$57,720.00	(\$61.00)	<u>(\$732.00)</u> -0.15%
5 6 Transportation - Firm Demand (Delivery Charge Firm DTQ) 7 8	2,595.4 GJ	x \$11.914	= \$371,059.20	2,595.4 GJ x	\$11.765 = \$366,418.56	(\$0.149)(\$4,640.64 <u>)</u> -0.95%
9 Delivery Charge - Firm MTQ 10 Rider 3 ESM 11 Rider 4 Delivery Rate Refund 12 Transportation - Firm (Delivery Charge Firm MTQ) 13	646,093.9 GJ 646,093.9 GJ 646,093.9 GJ	x (\$0.022)	= (14,214.0658)	646,093.9 GJ x 646,093.9 GJ x 646,093.9 GJ x	(\$0.022) = (14,214.0658)	(\$0.001) \$0.000 \$0.000	(\$646.0939) -0.13% 0.0000 0.00% 0.0000 0.00% (\$646.10) -0.13%
 14 15 Delivery Charge - Interruptible MTQ 16 Rider 3 ESM 17 Rider 4 Delivery Rate Refund 18 Transportation - Interruptible (Delivery Charge Interruptible MTQ) 19 20 21 Non-Standard Charges (not forecast) 	22,259.2 GJ 22,259.2 GJ 22,259.2 GJ	x (\$0.022)		22,259.2 GJ x 22,259.2 GJ x 22,259.2 GJ x	(\$0.022) = (489.7024)	(\$0.012) \$0.000 \$0.000	(\$267.1104) -0.05% 0.0000 0.00% 0.0000 0.00% (\$267.11) -0.05%
 UOR, Demand Surcharge, Balancing Service, Backstopping G Administration Charge Administration Charge Total (with effective \$/GJ rate) 	12 months	x \$79.00 <i>\$0.756</i>	= \$948.00 \$488,544.67	12 months x	\$78.00 = \$936.00 \$0.746 \$482,246.82	(\$1.00)(\$0.010)(\$	<u>(\$12.00)</u> 0.00% \$6,297.85 <u>)</u> -1.29%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

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RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	I	EXISTING JAI	NUARY 1, 2009 F	ATES		PROPOSED	APRIL 1, 2009 R	ATES		Annual Increase/Decrease	
1		Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bil
	COLUMBIA SERVICE - EXCEPT ELKVIEW COAL											
3 4	Basic Charge	12	months x	\$4,594.00 =	\$55,128.00	12	months x	\$4,537.00 =	\$54,444.00	(\$57.00)	(\$684.00)	-0.23%
5 6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	\$7.591 =	\$201,477.24	2,211.8	GJ x	\$7.496 =	\$198,955.80	(\$0.095)	(\$2,521.44)	-0.84%
7	Delivery Charge - Firm MTQ	413,966.7	GJ x	\$0.081 =		413,966.7	GJ x	\$0.080 =	. ,	(\$0.001)	(\$413.9667)	-0.14%
8	Rider 3 ESM	413,966.7	GJ x	(\$0.018) =		413,966.7	GJ x	(\$0.018) =	()	\$0.000	0.0000	0.00%
9	Rider 4 Delivery Rate Refund	413,966.7	GJ x	(\$0.003) =		413,966.7	GJ x	(\$0.003) =		\$0.000	0.0000	0.00%
10 11	Transportation - Firm (Delivery Charge Firm MTQ)				\$24,838.00				\$24,424.04	_	(\$413.96)	-0.14%
12	Delivery Charge - Interruptible MTQ											
13	- Apr. 1 to Nov. 1	6,582.4	GJ x	\$0.756 =	\$4,976.2944	6,582.4	GJ x	\$0.747 =	\$4,917.0528	(\$0.009)	(\$59.2416)	-0.02%
14	- Nov. 1 to Apr. 1	10,579.7	GJ x	\$1.090 =	. ,	10,579.7	GJ x	\$1.076 =		(\$0.014)	(148.1158)	-0.05%
15	Rider 3 ESM	17,162,1	GJ x	(\$0.018) =		17,162.1	GJ x	(\$0.018) =		\$0.000	0.0000	0.00%
16	Rider 4 Delivery Rate Refund	17,162.1	GJ x	(\$0.003) =		17,162.1	GJ x	(\$0.003) =		\$0.000	0.0000	0.00%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ				\$16,147.76	-			\$15,940.41	_	(\$207.35)	-0.07%
18												
	Non-Standard Charges (not forecast)											
20 21	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
22	Administration Charge	12	months x	\$79.00 =	\$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	0.00%
23										· · · -		
24	Total (with effective \$/GJ rate)	431,128.8		\$0.692	\$298,539.00	431,128.8		\$0.684	\$294,700.25	(\$0.008)	(\$3,838.75)	-1.29%
25 26										=		
	COLUMBIA SERVICE - ELKVIEW COAL											
	Basic Charge	12	months x	\$4,594.00 =	\$55,128.00	12	months x	\$4,537.00 =	\$54,444.00	(\$57.00)	(\$684.00)	-0.48%
29		0.070.0	0.1	64 704	***	0.070.0	0.1	A 4 7 00	****	(\$0.000)	(**********	0.50%
30 31	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	\$1.724 =		2,670.0	GJ x	\$1.702 =		(\$0.022)	(\$704.88)	-0.50%
32	Delivery Charge - Firm MTQ	392,395.4	GJ x	\$0.081 =		392,395.4	GJ x	\$0.080 =		(\$0.001)	(\$392.3954)	-0.28%
33 34	Rider 3 ESM Rider 4 Delivery Rate Refund	392,395.4 392,395.4	GJ x GJ x	(\$0.007) = (\$0.002) =		392,395.4 392,395.4	GJ x GJ x	(\$0.007) = (\$0.003) =		\$0.000	0.0000 (392.3954)	0.00% -0.28%
	Transportation - Firm (Delivery Charge Firm MTQ)	392,395.4	GJX	(\$0.002) =	\$28,252.47	392,395.4	GJX	(\$0.003) =	\$27,467.68	(\$0.001)	(\$92.3954)	-0.28%
36	Transportation - Tim (Delivery Charge Tim Wirk)				\$20,232.47				\$27,407.00	_	(\$704.75)	-0.5578
37	Delivery Charge - Interruptible MTQ											
38	- Apr. 1 to Nov. 1	10,579.7	GJ x	\$0.189 =	\$1,999.5633	10,579.7	GJ x	\$0.187 =	\$1,978.4039	(\$0.002)	(\$21.1594)	-0.01%
39	- Nov. 1 to Apr. 1	0.0	GJ x	\$0.270 =		0.0	GJ x	\$0.267 =		(\$0.003)	0.0000	0.00%
40	Rider 3 ESM	10,579.7	GJ x	(\$0.007) =	(74.0579)	10,579.7	GJ x	(\$0.007) =	(74.0579)	\$0.000	0.0000	0.00%
41	Rider 4 Delivery Rate Refund	10,579.7	GJ x	(\$0.002) =	(21.1594)	10,579.7	GJ x	(\$0.003) =	(31.7391)	(\$0.001)	(10.5797)	-0.01%
	Transportation - Interruptible (Delivery Charge Interruptible MTQ				\$1,904.35				\$1,872.61		(\$31.74)	-0.02%
43												
	Non-Standard Charges (not forecast)											
45 46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
	Administration Charge	12	months x	\$79.00 =	\$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	-0.01%
48	Automotion ondrigo	12	monulo X	ψι υ.υυ -	ψ 3 1 0.00	12	monuno x	ψιο.ου –	ψ550.00	(@1.00)	(#12.00)	-0.0170
	Total (with effective \$/GJ rate)	402,975.1		\$0.351	\$141,469.78	402,975.1		\$0.346	\$139,252.37	(\$0.005)	(\$2,217.41)	-1.57%
				÷3.001	,,	,01011	I .	÷3.0.10	,,_,	(\$0.000) =	(, , , , , , , , , , , , , , , , , , , 	

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

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RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular		EXISTING JAN	IUARY 1, 2009 F	RATES		PROPOSED	APRIL 1, 2009 RA	TES		Annual ncrease/Decrease	
1		Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bil
	LOWER MAINLAND SERVICE AREA											
3	Basic Charge	12	months x	\$134.20 =	\$1,610.40	12	months x	\$132.52 = <u></u>	\$1,590.24	(\$1.68)	(\$20.16)	-0.18%
5	Administration Charge	12	months x	\$79.00 =	\$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	-0.11%
7	Delivery Charge	4,100.0	GJ x	\$2.163 =	\$8,868.3000	4,100.0	GJ x	\$2.136 =	\$8,757.6000	(\$0.027)	(\$110.7000)	-1.00%
8	Rider 3 ESM	4,100.0	GJ x	(\$0.079) =	(323.9000)	4,100.0	GJ x	(\$0.079) =	(323.9000)	\$0.000	0.0000	0.00%
9	Rider 4 Delivery Rate Refund	4,100.0	GJ x	(\$0.013) =		4,100.0	GJ x	(\$0.022) =	(90.2000)	(\$0.009)	(36.9000)	-0.33%
10	Rider 5 RSAM	4,100.0	GJ x	\$0.001 =		4,100.0	GJ x	\$0.001 =	4.1000	\$0.000	0.0000	0.00%
	Transportation - Firm	.,			\$8,495.20	.,			\$8,347.60		(\$147.60)	-1.34%
12					<i></i>			-	<i>v</i> , v		(**************************************	
13 14	Non-Standard Charges (not forecast) UOR, Balancing gas, Backstopping Gas, Replacement Gas											
15 16	Total (with effective \$/GJ rate)	4,100.0		\$2,696	\$11.053.60	4,100.0		\$2.652	\$10,873.84	(\$0.044)	(\$470.76)	-1.63%
17		4,100.0		\$2.090	\$11,055.00	4,100.0		φ2.002 =	\$10,073.04	(\$0.044)	(\$179.76)	-1.03 //
		10		* 4 0 4 0 0	** *** **	10		\$400 F0	A4 500 04	(*** *** *	(**** *** *	0.400/
	Basic Charge	12	months x	\$134.20 =	\$1,610.40	12	months x	\$132.52 =	\$1,590.24	(\$1.68)	(\$20.16)	-0.16%
20												
	Administration Charge	12	months x	\$79.00 =	\$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	-0.10%
22												
23	Delivery Charge	4,700.0	GJ x	\$2.163 =		4,700.0	GJ x	\$2.136 =	\$10,039.2000	(\$0.027)	(\$126.9000)	-1.03%
24	Rider 3 ESM	4,700.0	GJ x	(\$0.079) =	(371.3000)	4,700.0	GJ x	(\$0.079) =	(371.3000)	\$0.000	0.0000	0.00%
25	Rider 4 Delivery Rate Refund	4,700.0	GJ x	(\$0.013) =	(61.1000)	4,700.0	GJ x	(\$0.022) =	(103.4000)	(\$0.009)	(42.3000)	-0.34%
26	Rider 5 RSAM	4,700.0	GJ x	\$0.001 =	4.7000	4,700.0	GJ x	\$0.001 =	4.7000	\$0.000	0.0000	0.00%
27	Transportation - Firm				\$9,738.40			-	\$9,569.20	_	(\$169.20)	-1.38%
28					·			-	· · · · · · · · · · · · · · · · · · ·		· · · ·	
	Non-Standard Charges (not forecast)											
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
31	eert, Balansing gae, Bashetopping eas, Hoplatement eas											
	I otal (with effective \$/GJ rate)	4,700.0		\$2.616	\$12,296.80	4,700.0		\$2.573	\$12,095.44	(\$0.043)	(\$201.36)	-1.64%
33		.,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	•	<i>\$</i> 2.070	+12,200.00	.,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,		=	<i><i><i></i></i></i>	(\$61616)	(+=++)	
		40		¢404.00	¢4 040 40	40		¢400.50	£4 500 04	(\$4.00.)	(*********	0.400/
	Basic Charge	12	months x	\$134.20 =	\$1,610.40	12	months x	\$132.52 = <u></u>	\$1,590.24	(\$1.68)	(\$20.16)	-0.18%
36												
	Administration Charge	12	months x	\$79.00 =	\$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	-0.11%
38												
39	Delivery Charge	4,200.0	GJ x	\$2.163 =		4,200.0	GJ x	\$2.136 =	\$8,971.2000	(\$0.027)	(\$113.4000)	-1.01%
40	Rider 3 ESM	4,200.0	GJ x	(\$0.079) =		4,200.0	GJ x	(\$0.079) =	(331.8000)	\$0.000	0.0000	0.00%
41	Rider 4 Delivery Rate Refund	4,200.0	GJ x	(\$0.013) =	```	4,200.0	GJ x	(\$0.022) =	(92.4000)	(\$0.009)	(37.8000)	-0.34%
42	Rider 5 RSAM	4,200.0	GJ x	\$0.001 =		4,200.0	GJ x	\$0.001 =	4.2000	\$0.000	0.0000	0.00%
43	Transportation - Firm				\$8,702.40			-	\$8,551.20		(\$151.20)	-1.34%
44								-				
45	Non-Standard Charges (not forecast)	1										
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas	1										
47												
48	Total (with effective \$/GJ rate)	4,200.0		\$2.681	\$11,260.80	4,200.0		\$2.637	\$11,077.44	(\$0.044)	(\$183.36)	-1.63%
10		1,200.0		φ 2 .007	÷,200.00	.,200.0		÷2.007	*		(+.00.00)	

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

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RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

1.1.4.4	RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE											
Line No.	Particular	EXISTING JANUARY 1, 2009 RATES			PROPOSED APRIL 1, 2009 RATES				Annual Increase/Decrease			
1		Volu	ime	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bil
2	LOWER MAINLAND SERVICE AREA					-						
3 4	Basic Charge	12	months x	\$594.00 =	\$7,128.00	12	months x	\$587.00 =	\$7,044.00	(\$7.00)	(\$84.00)	-0.24%
5	Administration Charge	12	months x	\$79.00 =	\$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	-0.03%
6 7	Transportation - Firm Demand	97.3	GJ x	\$14.840 =	\$17,327.16	97.3	GJ x	\$14.655 =	\$17,111.16	(\$0.185)	(\$216.00)	-0.62%
8		17.010.1	<u></u>	* •• •••	* 40.004.4000	47.040.4	<u></u>	A O F OO	* 40 500 7000	(********	(\$404,7007)	0.000/
9	Delivery Charge	17,819.1	GJ x	\$0.600 =		17,819.1	GJ x	\$0.593 =	\$10,566.7263	(\$0.007)	(\$124.7337)	-0.36%
10 11	Rider 3 ESM	17,819.1	GJ x GJ x	(\$0.060) =		17,819.1	GJ x GJ x	(\$0.060) =	(1,069.1460)	\$0.000	0.0000	0.00%
	Rider 4 Delivery Rate Refund	17,819.1	GJX	(\$0.009) =		17,819.1	GJX	(\$0.012) =	(213.8292)	(\$0.003)	(53.4573)	-0.15%
12 13	Transportation - Firm				\$9,461.94			—	\$9,283.75	-	(\$178.19)	-0.51%
14 15 16	Non-Standard Charges (not forecast) UOR, Balancing gas, Backstopping Gas, Replacement Gas											
17	Total (with effective \$/GJ rate)	17,819.1	=	\$1.957	\$34,865.10	17,819.1		\$1.929	\$34,374.91	(\$0.028)	(\$490.19)	-1.41%
18	INLAND SERVICE AREA											
		10	months x	\$594.00 =	\$7,128.00	10	months x	\$587.00 =	\$7,044.00	(\$7.00.)	(\$94.00)	-0.11%
20	Basic Charge	12	monuns x	\$594.00 =	\$7,120.00	12	monuns x	\$587.00 =	\$7,044.00	(\$7.00)	(\$84.00)	-0.11%
	Administration Charge	12	months x	\$79.00 =	\$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	-0.02%
	Transportation - Firm Demand	231.3	GJ x	\$14.840 =	\$41,189.88	231.3	GJ x	\$14.655 =	\$40,676.40	(\$0.185)	(\$513.48)	-0.70%
26	Delivery Charge	45,504.2	GJ x	\$0.600 =	\$27,302.5200	45,504.2	GJ x	\$0.593 =	\$26,983.9906	(\$0.007)	(\$318.5294)	-0.43%
27	Rider 3 ESM	45,504.2	GJ x	(\$0.060) =		45,504.2	GJ x	(\$0.060) =	(2,730.2520)	\$0.000	0.0000	0.00%
28	Rider 4 Delivery Rate Refund	45,504.2	GJ x	(\$0.009) =		45,504.2	GJ x	(\$0.012) =	(546.0504)	(\$0.003)	(136.5126)	-0.19%
	Transportation - Firm	45,504.2	00 1	(\$0.005) =	\$24,162.73	40,004.2	00 1	(\$0.012) =	\$23,707.69	(\$0.000)	(\$455.04)	-0.62%
30					ψ 2 4,102.75			-	<i>420,101.00</i>	-	(#+55.04)	-0.02 /0
	Non-Standard Charges (not forecast)											
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
33	OON, Dalancing gas, Dackstopping Gas, Replacement Gas											
	Total (with effective \$/GJ rate)	45,504.2		\$1.614	\$73,428.61	45,504.2		\$1.590	\$72,364.09	(\$0.024)	(\$1,064.52)	-1.45%
35		-	-					=				
36	COLUMBIA SERVICE											
37	Basic Charge	12	months x	\$594.00 =	\$7,128.00	12	months x	\$587.00 =	\$7,044.00	(\$7.00)	(\$84.00)	-0.14%
38	5							· -			<u>/</u> _	
39	Administration Charge	12	months x	\$79.00 =	\$948.00	12	months x	\$78.00 =	\$936.00	(\$1.00)	(\$12.00)	-0.02%
40										(****/	<u>, i i j</u>	
	Transportation - Firm Demand	210.0	GJ x	\$14.840 =	\$37,396.80	210.0	GJ x	\$14.655 =	\$36,930.60	(\$0.185)	(\$466.20)	-0.79%
42	, , , , , , , , , , , , , , , , , , , ,			• • •				• • • • •	,	((, - /	
43	Delivery Charge	25,484.6	GJ x	\$0.600 =	\$15,290.7600	25,484.6	GJ x	\$0.593 =	\$15,112.3678	(\$0.007)	(\$178.3922)	-0.30%
44	Rider 3 ESM	25,484.6	GJ x	(\$0.060) =		25,484.6	GJ x	(\$0.060) =	(1,529.0760)	\$0.000	0.0000	0.00%
45	Rider 4 Delivery Rate Refund	25,484.6	GJ x	(\$0.009) =		25,484.6	GJ x	(\$0.012) =		(\$0.003)	(76.4538)	-0.13%
	Transportation - Firm	2, 22 110		(\$13,532.32	.,		·····/	\$13,277.48	(+)	(\$254.84)	-0.43%
47	·······							-	÷.•,=•	_	(+=++ /	0
	Non-Standard Charges (not forecast)											
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
50	,											
	Total (with effective \$/GJ rate)	25,484.6		\$2.315	\$59,005.12	25,484.6		\$2.283	\$58,188.08	(\$0.032)	(\$817.04)	-1.38%
	·	•	=		·			=		. / =	· /	

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

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RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line	KATE SCHEDULE 27 • INTERROFTIBLE I-SERVICE						
No. Particular	EXISTING JAN	NUARY 1, 2009 RATES	PROPOSED APRIL 1, 2009 RATES	Annual Increase/Decrease			
1	Volume	Rate Annual \$	Volume Rate Annual \$	% of Previous <u>Rate</u> Annual \$ Annual Bil			
2 LOWER MAINLAND SERVICE AREA 3 Basic Charge	12 months x	\$891.00 = \$10,692.00	12 months x \$880.00 = \$10,560.00	(\$11.00) (\$132.00) -0.23%			
4 5 Administration Charge 6	12 months x	\$79.00 = \$948.00	12 months x \$78.00 = \$936.00	(\$1.00) (\$12.00) -0.02%			
 Delivery Charge Rider 3 ESM Rider 4 Delivery Rate Refund Transportation - Interruptible 	47,047.2 GJ x 47,047.2 GJ x 47,047.2 GJ x	\$1.003 = \$47,188.3416 (\$0.036) = (1.693.6992) (\$0.006) = (282.2832) \$45,212.36	$\begin{array}{rrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrr$	(\$0.013) (\$611.6136) -1.08% \$0.000 0.0000 0.00% (\$0.002) (\$4.0944) -0.17% (\$705.71) -1.24%			
 Non-Standard Charges (not forecast) UOR, Balancing gas, Backstopping Gas Total (with effective \$/GJ rate) 16 17 18 	47,047.2	\$1.208 \$56,852.36	<u>47,047.2</u> \$1.190 <u>\$56,002.65</u>	(\$0.018) (\$849.71) -1.49%			
19 20 INLAND SERVICE AREA 21 Basic Charge 22	12 months x	\$891.00 = \$10,692.00	12 months x \$880.00 = \$10,560.00	(\$11.00)			
23 Administration Charge	12.0 months x	\$79.00 = \$948.00	12.0 months x \$78.00 = \$936.00	(\$1.00) (\$12.00) -0.02%			
 24 25 Delivery Charge 26 Rider 3 ESM 27 Rider 4 Delivery Rate Refund 28 Transportation - Interruptible 29 30 	48,727.3 GJ x 48,727.3 GJ x 48,727.3 GJ x	\$1.003 = \$48,873.4819 (\$0.036) = (1,754.1828) (\$0.006) = (292.3638) \$46,826.94	$\begin{array}{rrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrrr$	(\$0.013) (\$633.4549) -1.08% \$0.000 0.0000 0.00% (\$0.002) (97.4546) -0.17% (\$730.91) -1.25%			
 Non-Standard Charges (not forecast) UOR, Balancing gas, Backstopping Gas Total (with effective \$/GJ rate) 	48,727.3	\$1.200 \$58,466.94	\$1.182\$57,592.03	(\$0.018) (\$874.91) -1.50%			

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TAB 6 PAGE 13

DRAFT ORDER

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

and

Filings by Terasen Gas Inc. regarding 2009 First Quarter Gas Costs Report and Rate Changes effective April 1, 2009 for the Lower Mainland, Inland, Columbia Service Areas

BEFORE:

[March xx, 2009]

WHEREAS:

- A. By Order No. G-127-08 dated September 11, 2008, the British Columbia Utilities Commission (the "Commission") approved a decrease in the Commodity Cost Recovery Charge for the Lower Mainland, Inland, and Columbia Service Areas, effective October 1, 2008; and
- B. By Order No. G-187-08 dated December 11, 2008, the Commission ordered that no change be made to the Commodity Cost Recovery Charge effective January 1, 2009; and
- C. By Order No. G-191-08 dated December 11, 2008, the Commission approved increased delivery charges for customers served under Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X, 4, 5, 6, 7, 22, 22A, 22B, 23, 25, and 27 effective January 1, 2009, as provided in the Amended Application of the Terasen Gas Inc. ("Terasen Gas") 2008 Annual Review of 2009 Revenue Requirements and Rates; and
- D. On March 5, 2009, pursuant to Commission Letter No. L-5-01, Terasen Gas filed its 2009 First Quarter Report on Commodity Cost Reconciliation Account ("CCRA") and Midstream Cost Reconciliation Account ("MCRA") balances and gas commodity charges for the Lower Mainland, Inland and Columbia Service Areas effective April 1, 2009 that were based on February 24, 2009 forward gas prices (the "2009 First Quarter Report"); and
- E. The 2009 First Quarter Report forecasts that commodity cost recoveries at current rates would be 126.4 percent of costs for the following 12 months; and requests a decrease of \$1.574/GJ to the Commodity Cost Recovery Charges from \$7.536/GJ to \$5.962/GJ for natural gas sales rate class customers in Lower Mainland, Inland, and Columbia Service Areas effective April 1, 2009; and
- F. The 2009 First Quarter Report forecasts MCRA balance at existing rates to be approximately an after-tax deficit of \$49 million at December 31, 2009; and
- G. The 2009 First Quarter Report proposes a decrease to delivery charges for customers served under Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X, 4, 5, 6, 7, 22, 22A, 22B, 23, 25, and 27, effective April 1, 2009, to correct a Revenue Deficiency overstatement in the Amended Application of the Terasen Gas 2008 Annual Review of 2009 Revenue Requirements and Rates; and
- H. The 2009 First Quarter Report proposes that the forecast amount over collected from customers for the period January 1, 2009 through March 31, 2009, be refunded via a nine month Delivery Rate Refund Rider effective April 1, 2009 through the existing Rate Rider 4 mechanism for customers served under Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 4, 5, 6, 7, 22, 22A, 22B, 23, 25, and 27; and

DRAFT ORDER

- I. The aggregate rate changes would decrease Lower Mainland Rate Schedule 1 rates by \$1.643/GJ, which would reduce a typical residential customer's annual bill by approximately \$156 or 12.7 percent, with an average annual consumption of 95 GJ; and
- J. The Commission concludes that the requested changes as outlined in the 2009 First Quarter Report should be approved.

NOW THEREFORE pursuant to Section 58, 60, 61, 61(4) and 124 of the Utilities Commission Act, the Commission orders as follows:

- 1. The Commission approves the proposed flow through decrease to the Commodity Cost Recovery Charges for Sales Rate Classes within the Lower Mainland, Inland, and Columbia Service Areas, effective April 1, 2009, to a rate of \$5.962/GJ as set out in the 2009 First Quarter Report.
- 2. The Midstream Cost Recovery Charges remain unchanged.
- 3. The Commission approves the proposed delivery related changes, including the Delivery Rate Refund Rider (Rate Rider 4), for customers served under Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X, 4, 5, 6, 7, 22, 22A, 22B, 23, 25, and 27 effective April 1, 2009 as set out in the 2009 First Quarter Report.
- 4. Terasen Gas will notify all customers that are affected by the rate changes with a bill insert or bill message to be included with the next monthly gas billing.

DATED at the City of Vancouver, In the Province of British Columbia, this day of March, 2009.

BY ORDER