TERASEN GAS INC.
2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT

2004 ANNUAL REVIEW

November 19, 2004

AGENDA REVIEW

AGENDA - TGI

Terasen Gas

Agenda and Regulatory Recap		-	**Scott Thomson**
Welcome / Introduction		-	**Bill Grant**
Terasen Opening Remarks & Report		-	**Randy Jespersen**
	2004 Activities		
	Challenges for 2005		
2005 PBR Cost Drivers			
	Volumes and Revenues	-	**Rick Parnell**
	Formula Driven Rate Base and Plant Additions	-	**Tom Loski**
	Formula O&M Expenses	-	**Tom Loski**
	Accounting and Tax Matters	-	**Scott Thomson**
2005 Revenue Requirements and Rate Outlook			
	Gas Commodity Cost & GCRA Outlook	-	**Tania Specogna**
	Revenue Requirement Results	-	**Tom Loski**
	Overall Customer Rate Impacts	-	**Tom Loski**

AGENDA – TGI - page 2

- **Other Information Pertaining to the TGI 2004-2007 PBR Settlement**
  - 5 Year Major Capital Plan
  - Material Efficiency Initiatives
  - Code of Conduct and Transfer Pricing Policy Reports
  - Shared Services Agreement
- **Conclusions**
- **LUNCH BREAK**

Welcome/Introduction

Bill Grant
Executive Director, BCUC

Terasen Gas Opening Remarks

Randy Jespersen
President

Activities for 2004 - TGI

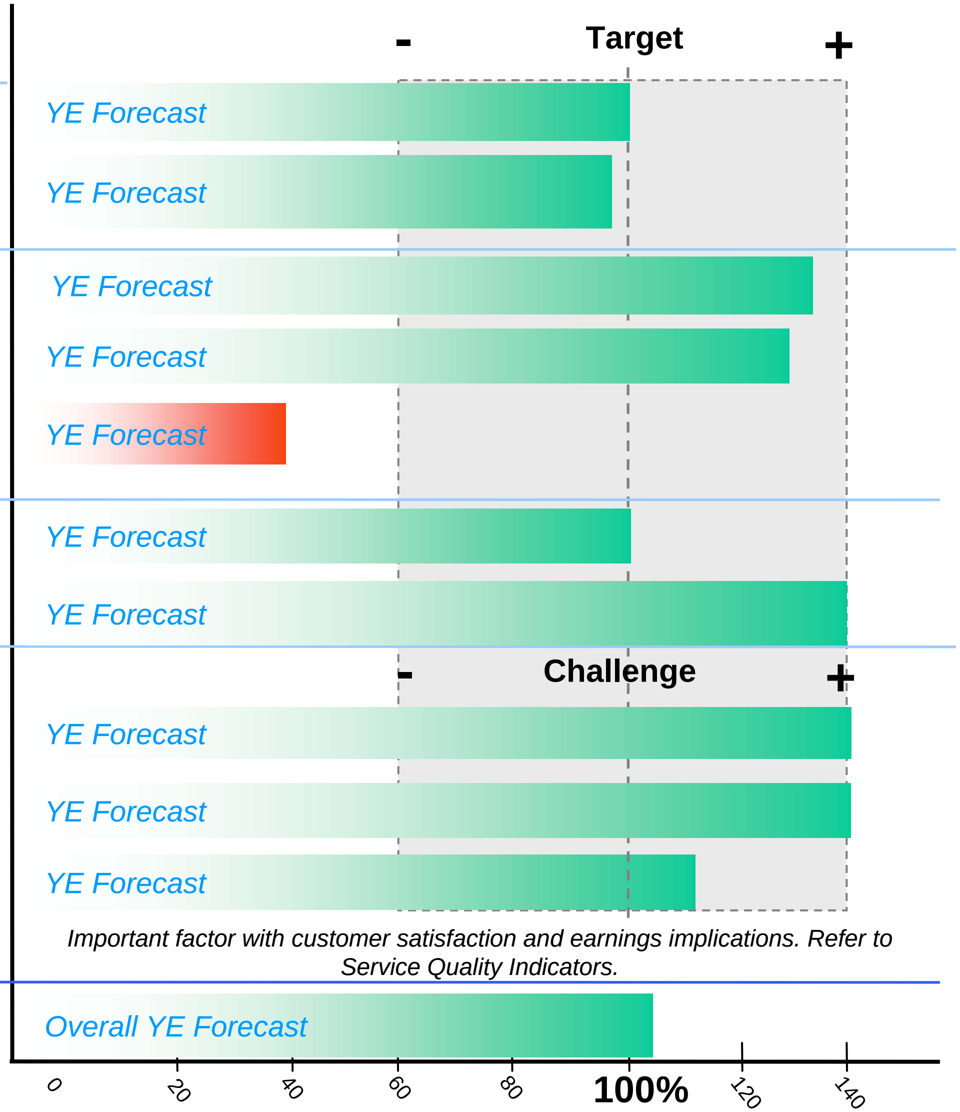
- Integration/Restructuring
  - Implementing our plan & supporting the new organization
- Operational Excellence
  - Exceed scorecard targets
  - Avoid SQI penalties
- Improve on Customer Attachments
  - Rate, time, cost, flexibility
- Focused Business Development

Activities for 2004 - TGI

- Commercial Commodity Unbundling ✓
- Stable Rate Option ✓
- Regional Resource Planning ✓

Terasen Gas Group 2004 Scorecard
September 2004 Results

		Weight
FINANCIAL	1. Inc. Earnings Per Share*	10.0
	2. Gas Segment Earnings Before Interest & Taxes	25.0
CUSTOMER	3. O&M per Customer	10.0
	4. Base Capital	10.0
	5. Customer Survey Score	10.0
CONCEPT TO CASH	6. Credit & Collections	10.0
	7. Customer Additions	10.0
EMPLOYEE	8. Vehicle Accidents	5.0
	9. Lost Time Injuries	5.0
	10. Wellness	5.0
	11. Public Safety	
TOTAL	Overall Weighting	100



Challenges for 2005 - TGI

- ROE & Capital Structure Application
- BC Hydro Rate Design
- Customer Growth Strategy
- Continued Operational Excellence

2004 Summary Results

2004 Update

Customer Additions and Capital Expenditures

	2004 Test Yr	2004 Projected
Customer Additions	8,064	11,412
Customers – End of Year	782,258	786,928
Average Customer Count	777,779	779,498
Capital Expenditures	$85,378	$91,453

2004 Update

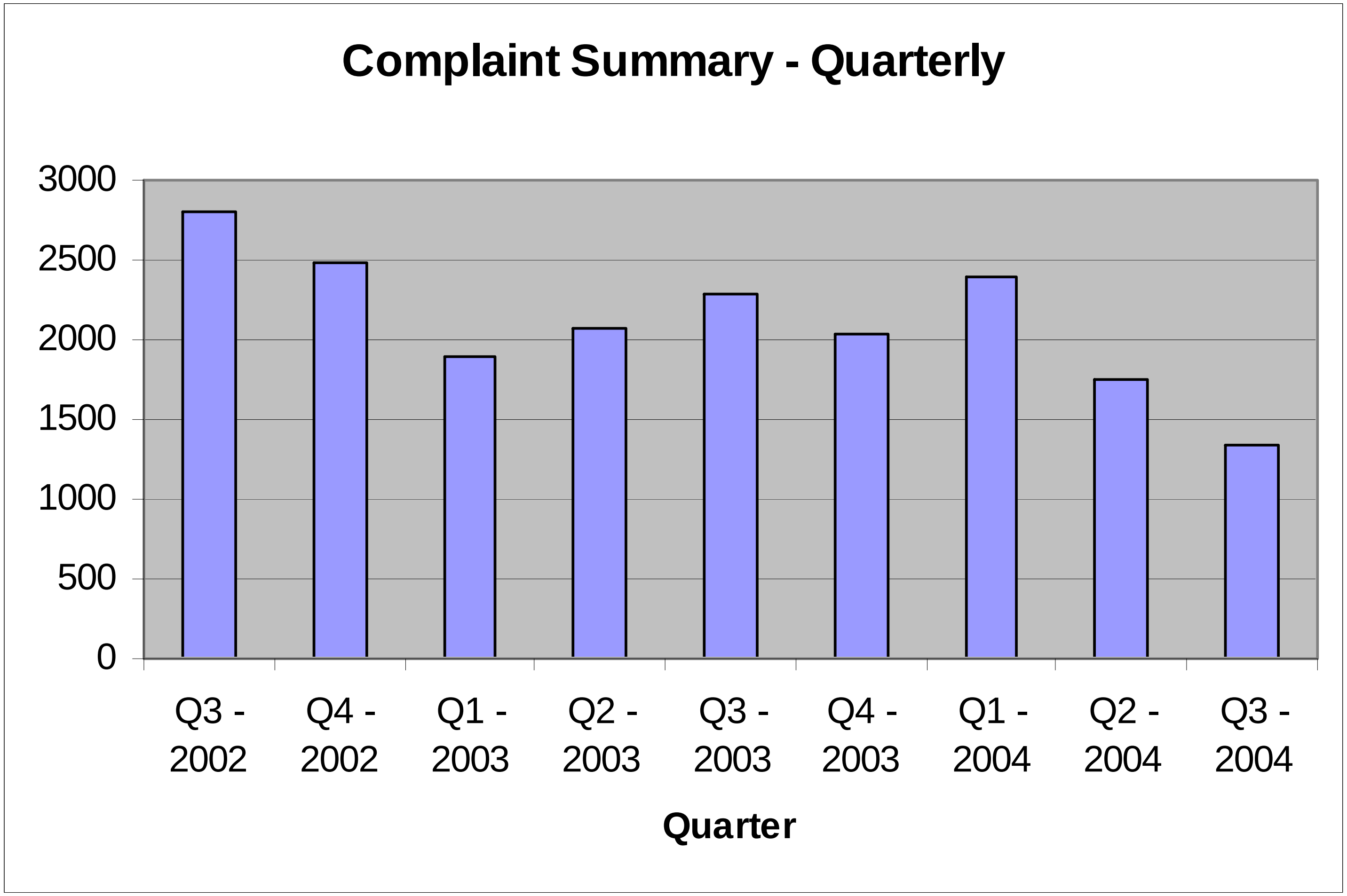
	2004 Test Yr	2004 Projected
O & M Expenses		
Before Restructuring Costs	$159,417	$147,564
After Restructuring Costs		$157,135
ROE		
Before Restructuring Costs	9.15%	9.94%
After Restructuring Costs		9.13%

- We expect restructuring cost will erode the overearned results in 2004. However, we expect the productivity improvements gained to endure and deliver positive results in the remaining PBR years.

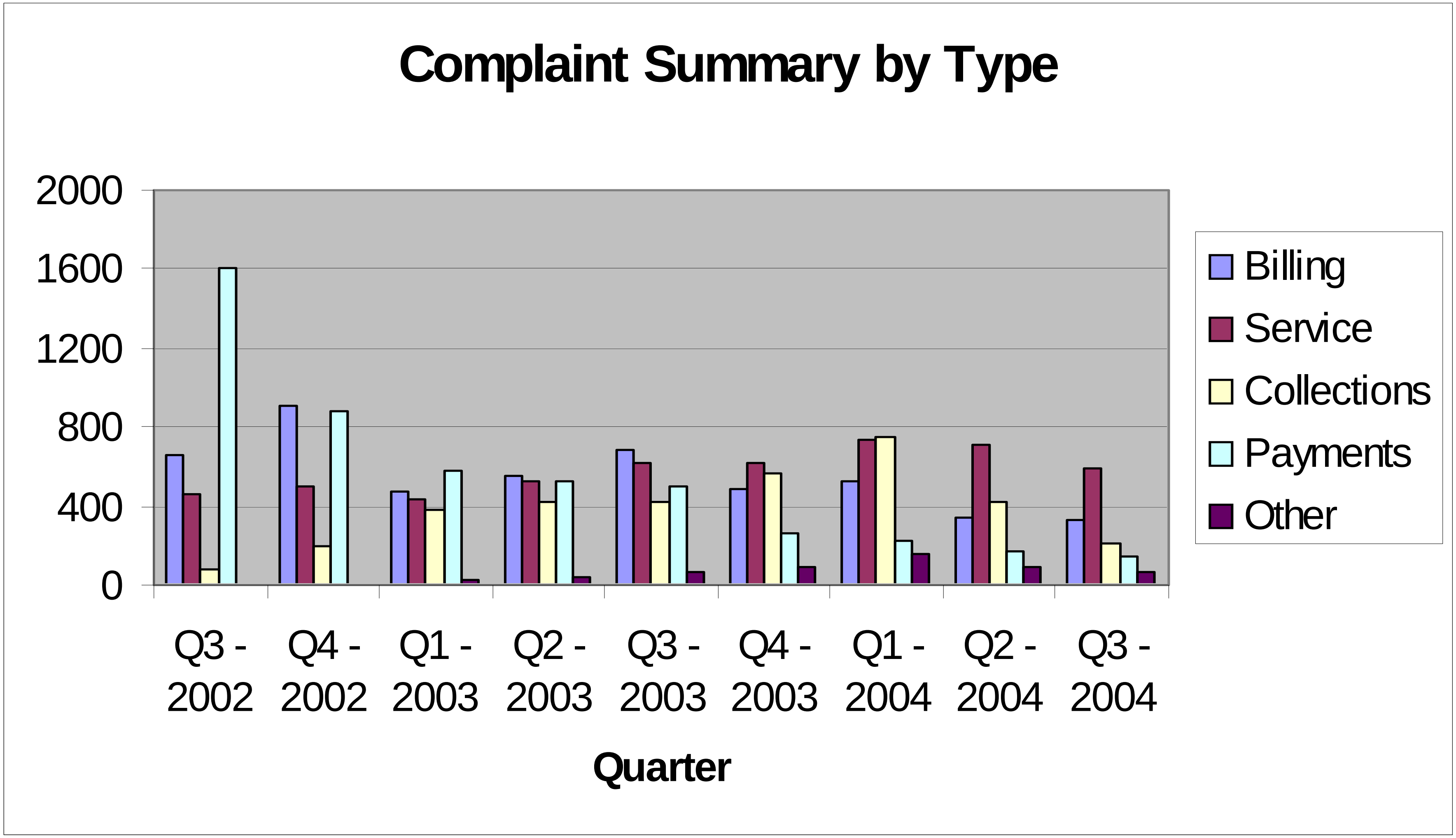
Customer Care

Jan Marston

Customer Complaints

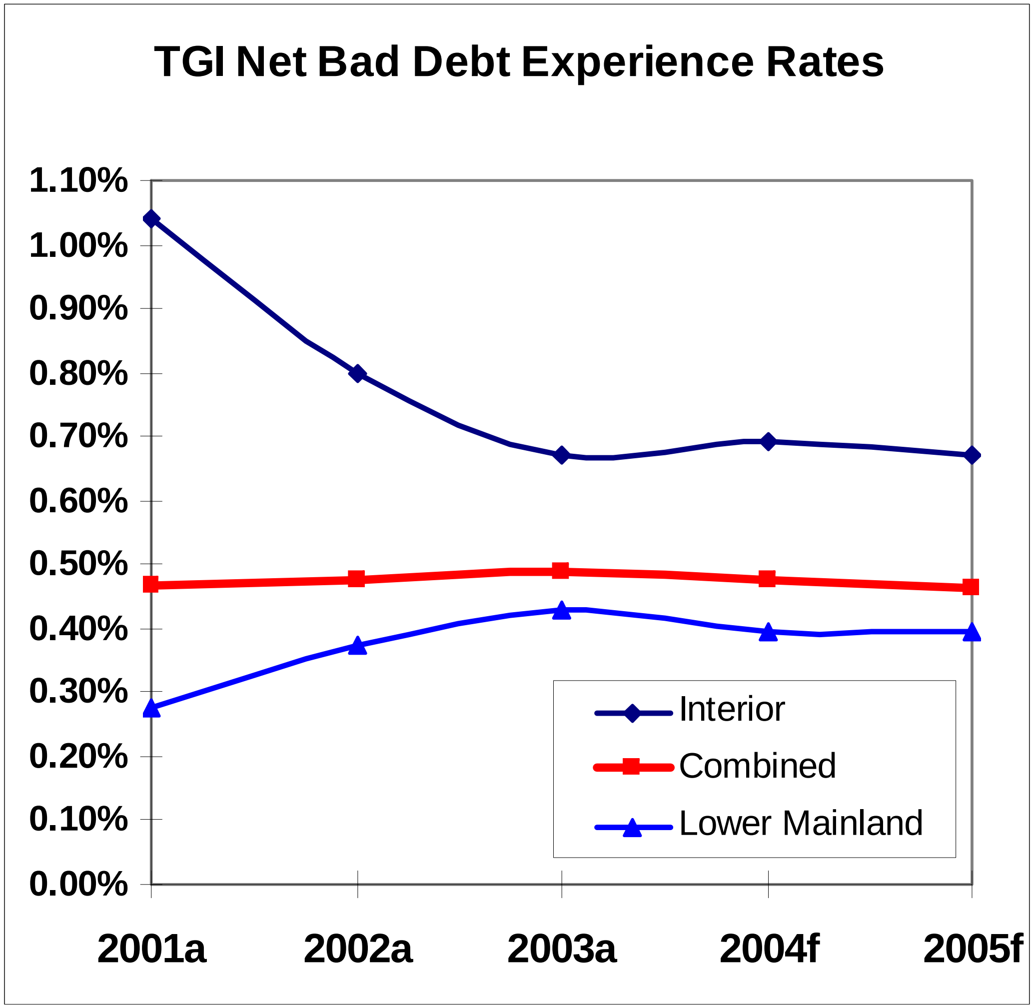


Customer Complaints

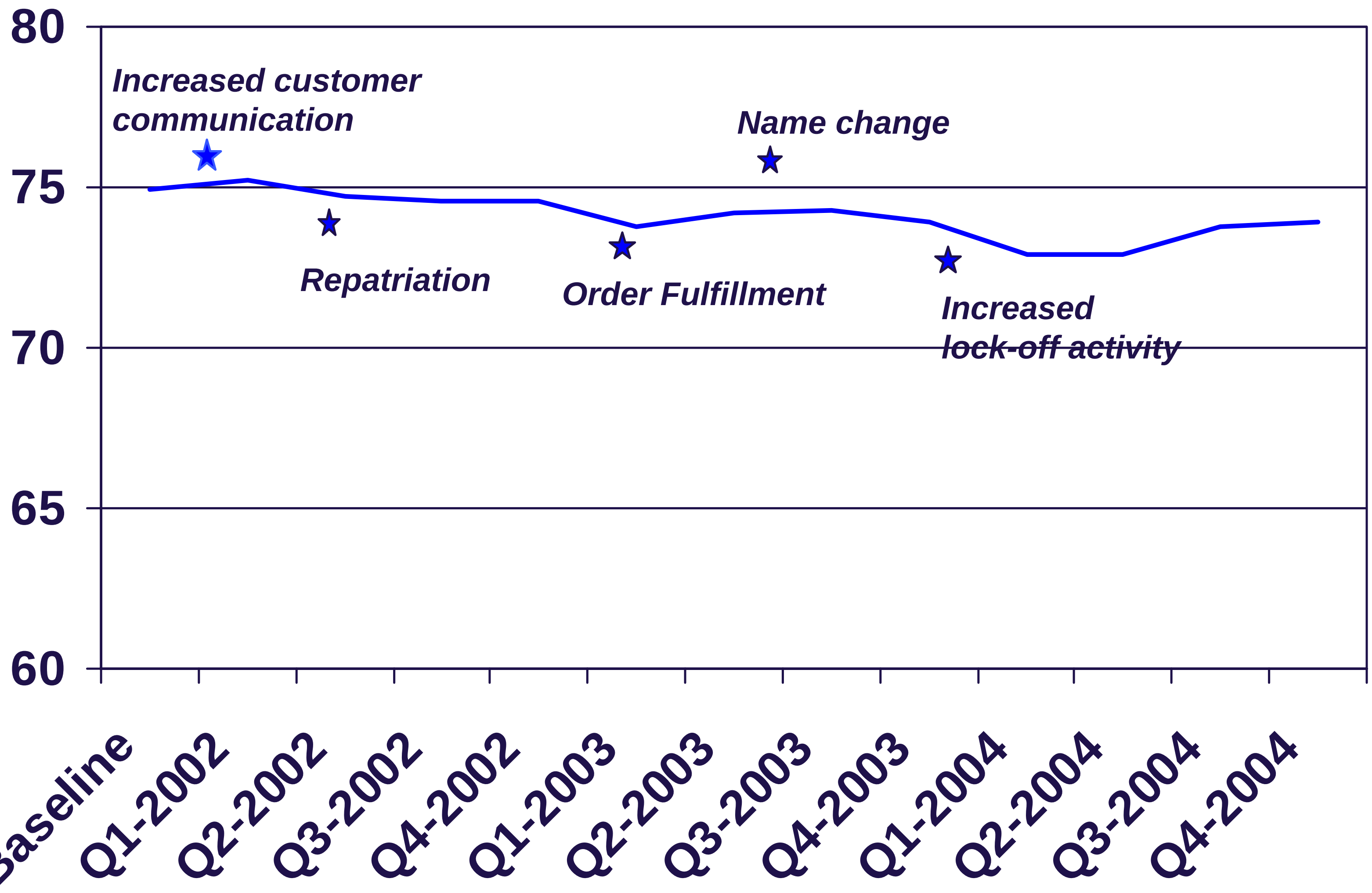


Bad Debt Experience Trend

- Improvements in credit & collections processes helped to improve the experience rate in the Interior & manage the transition from BC Hydro in the Lower Mainland since 2002
- Trend shows improving experience rates
- Current bad debt as a percentage of sales revenue is 0.47%



Customer Satisfaction Index Trend



Service Quality Indicators
October 2004

Terasen Gas

	Performance Indicator	2003 Actuals	2004 YTD Actuals	2004 Target
1	**Emergency Response Time** - Time Dispatched to Site - Emergency - Blowing Gas	22:00 minutes	**21:36 minutes**	**<21:06 minutes**
2	**Speed of Answer – Emergency** (% of calls answered within 30 sec.)	96.3%	**97.7%**	**>95%**
3	**Speed of Answer – Non-Emergency** (% of calls answered within 30 sec.)	76.4%	**77.8%**	**>75%**
4	**Transmission Reportable Incidents**	3	**2**	**≤2**
5(a)	**Index of Customer Bills Meeting Criteria**	2.63	**2.00**	**< 5**
5(b)	**Percent of Transportation Customer Bills Accurate**	99.8%	**96.4%**	**>99.5%**
6	**Meter Exchange Appointment Activity**	92.6%	**93.8%**	**>92.2%**
7	**Transportation Meter Measurement First Report < 10%**	97.4%	**97.3%**	**>90.0%**
8	**Independent Customer Satisfaction Survey**	73.9%	**73.8%**	**74%**
9	**Number of Customer Complaints to BCUC**	101	**173**	**101**
10	**Number of Prior Period Adjustments**	24	**16**	**24**

	Directional Indicators		
1	Leaks per Kilometre of Distribution Mains	0.0040 (134 leaks)	**0.0040 (133 leaks)**
2	Number of Third Party Distribution System Incidents	1,459 incidents	**1,323**

Utilities Strategies Project Update

November 19, 2004

Utilities Strategies Project Update

New management structure for 2004

- Single management team
- Common work practices and IT platforms introduced in 2004 – work continues
- Cost efficiencies flowed to both entities
- Total headcount reduced by 115 positions

Summary of Anticipated USP Benefits

2004 – 2007 Period*:

2004 Savings projected	$ 10.5 m
2005 Anticipated savings	$ 9.9 m
2006 Anticipated savings	$ 9.9 m
2007 Anticipated savings	$ 9.9 m
Total Restructuring cost	$-15.5 m
Net Benefits of USP	$ 24.6m

*net of depreciation

Summary of Capital Investments
(000)

	2004	2005
Order Fulfillment System	$ 700	$ 200
Back Office Business Systems	$ 1,350	$ 150
Meter Mgt & Mobile Systems	$ 100	$ 1,700
AM/FM/Drafting Systems	$ 600	$ 100
Infrastructure Integration	$ 450	$ 950
Others	$ 400	$ 300
Total	$ 3,600	$ 4,400

2005 PBR Cost Drivers

2005 Sales Volumes and Revenues

Rick Parnell

Forecast Summary

- Housing starts continue strong into 2005
- Economic recovery continues into 2005
- Conservation remains a key behavioral driver
- Continued concern for the competitive position of natural gas
- Expect 2005 to be a continuation from 2004
  - Use rates stabilizing
  - Residential and Commercial additions

Residential & Commercial Accounts

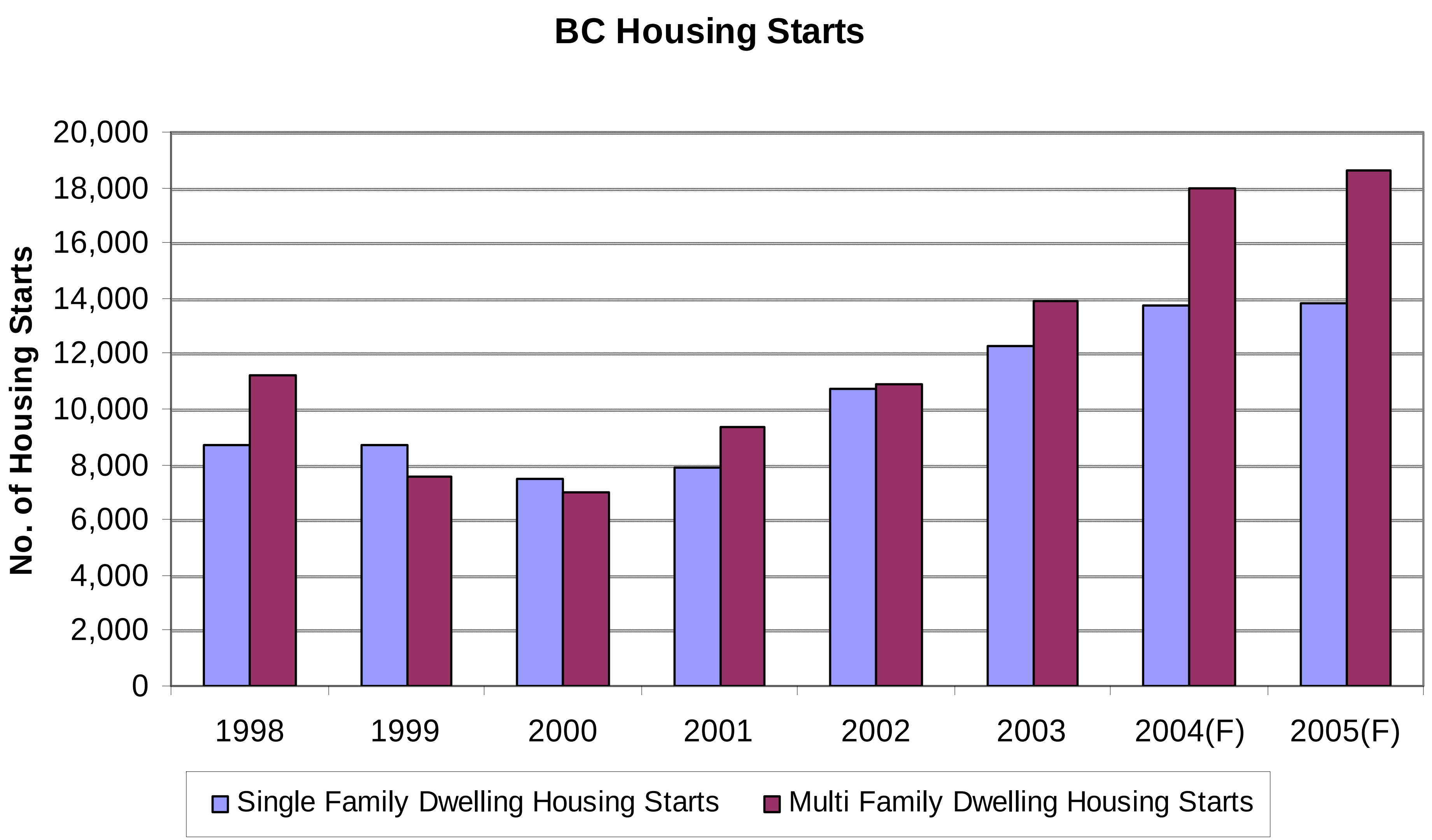
What are the Trends?

- More New Residential Customers
  - More potential additions
  - The challenge of more multiple unit housing
  - Gas commodity prices remain relatively high

- Stabilization of the Commercial Customer Base
  - Shift toward larger commercial operations
  - Strengthening economic recovery
  - Business cycle lags

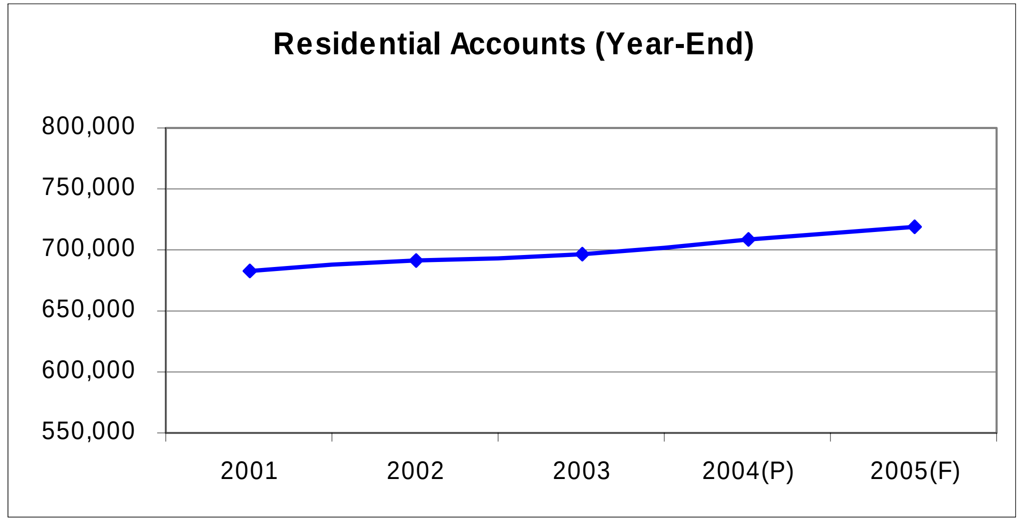
Note: Residential includes Rate 1; Commercial includes Rates 2, 3, & 23

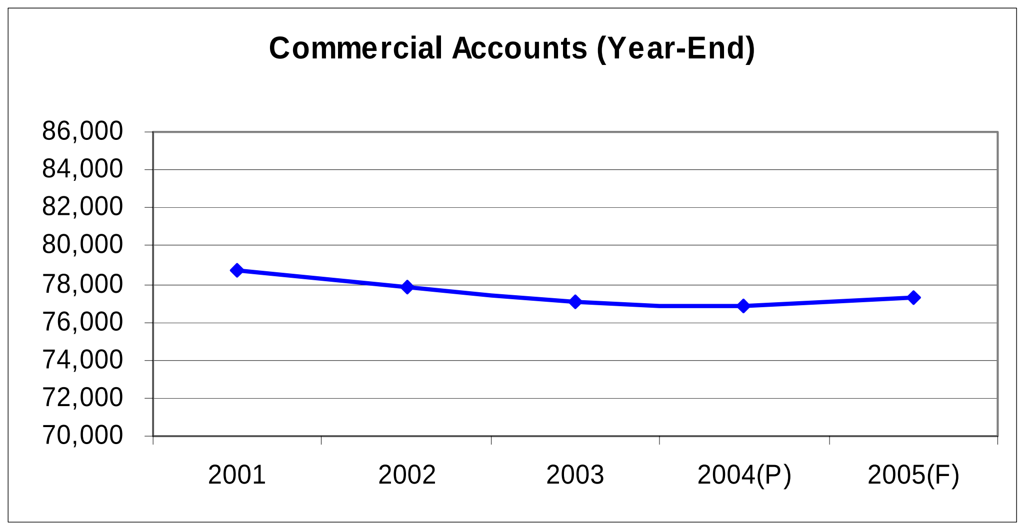
CMHC Housing Starts



Residential & Commercial Accounts

- Net Residential and Commercial additions forecast to grow in 2005
  - 10,200 Residential & Commercial additions in 2005
- Why?
  - Moderate changes in gas costs
  - Electricity rates somewhat higher
  - Strength in housing market through 2005, with shift to multi-family dwellings
  - Continued recovery in the economy
  - Consumer confidence improving



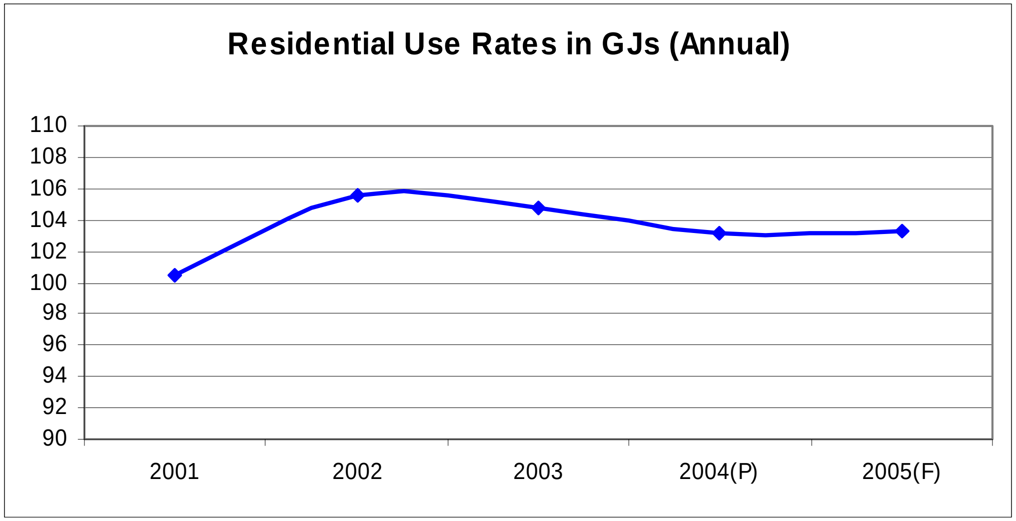


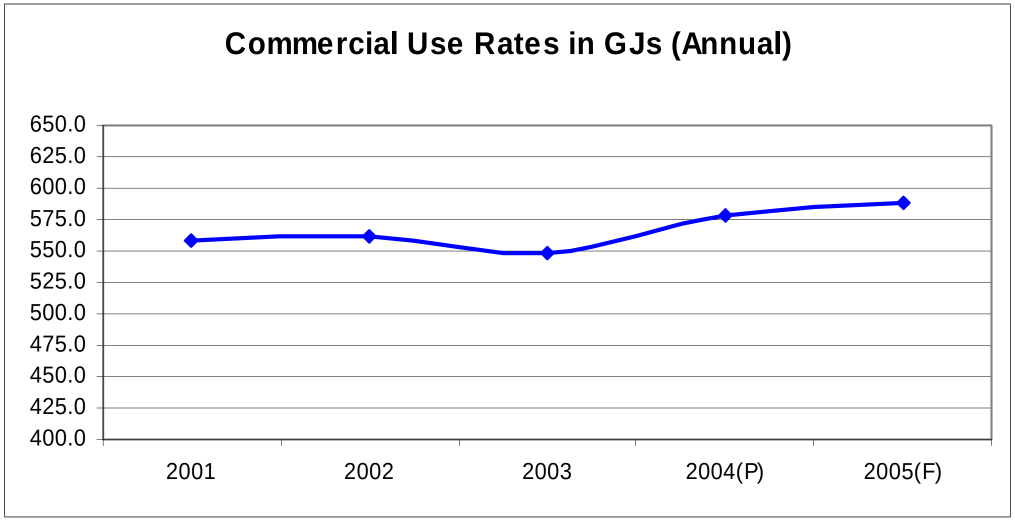
Note: Residential includes Rate 1; Commercial includes Rates 2, 3, & 23

Residential & Commercial Usage (Normalized)

Why is it down?

- Reduced Usage by New Customers
  - Better appliance efficiency
  - Improved insulation
  - More apartments and townhouses
- Reduced Usage by Existing Customers
  - Energy conservation
  - Appliance replacement
  - Electric space heater use





Note: Residential includes Rate 1; Commercial includes Rates 2, 3, & 23

Industrial & Transportation Forecast Methodology

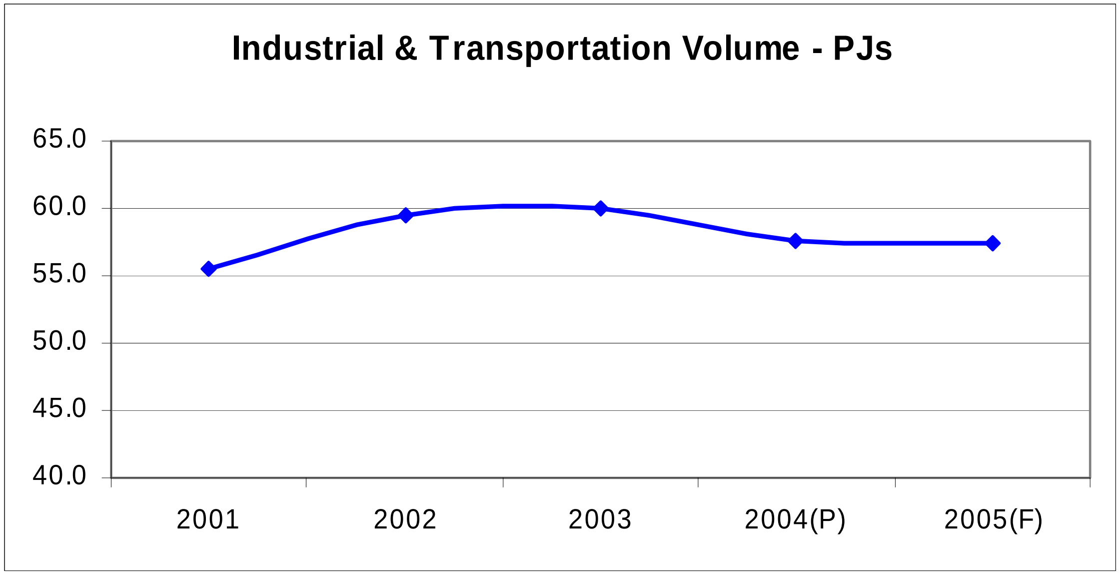
Terasen Gas

- Customer Survey methodology used for all Industrial & Transportation customers
  - Small number of customers, especially for analysis by industry
  - Plans of one or a few industrial customers can seriously impact forecast results
- Survey conducted during the summer of 2004
  - 409 useable survey responses, representing about 35% of industrial customers by number, and nearly 59% of industrial customers by volume
  - Survey results support an unchanged industrial demand projection for 2005 compared with 2004

Note: Industrial & Transportation includes Rates 5, 7, 22, 25, & 27; excludes Burrard Thermal & TGVI.

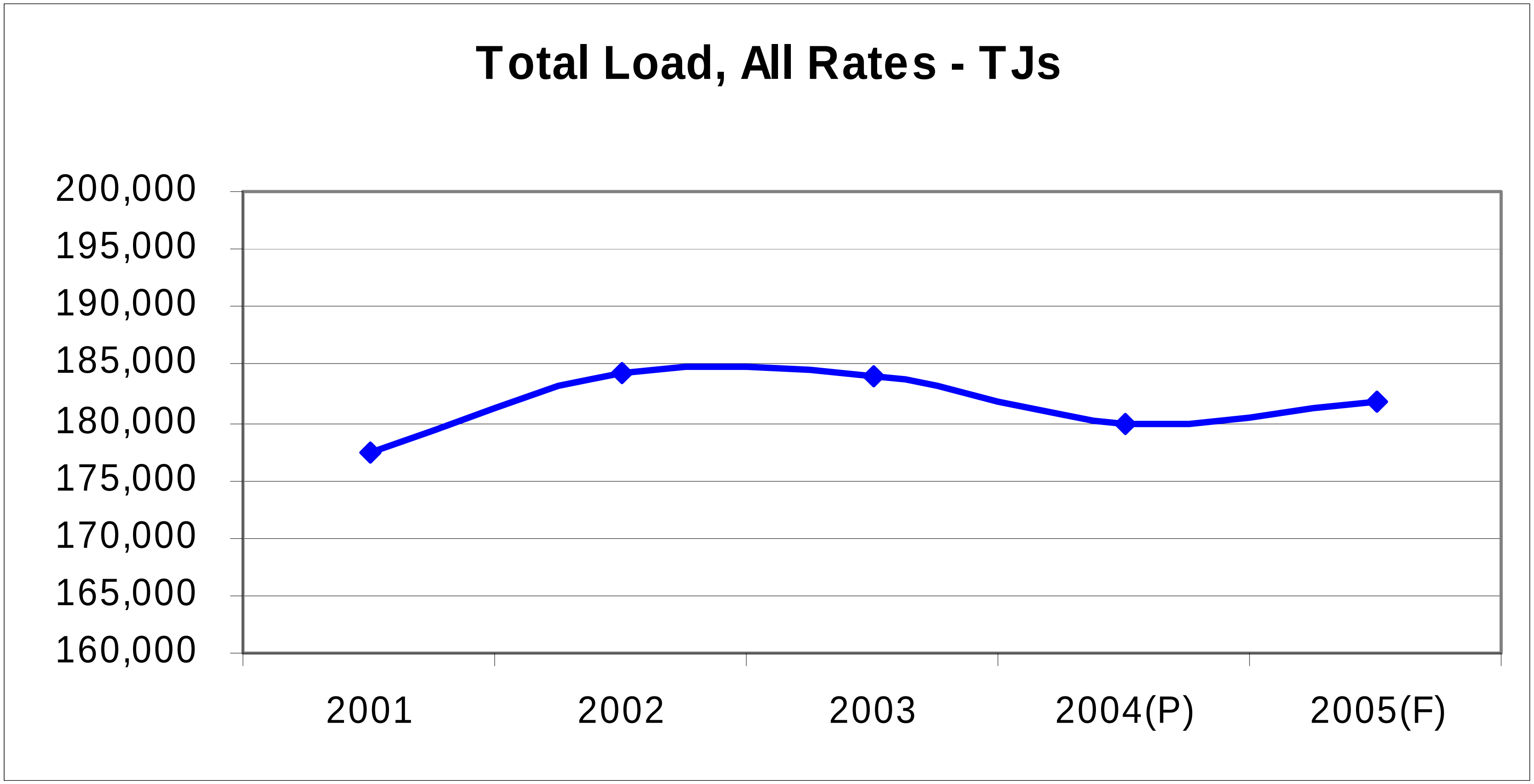
Industrial & Transportation Load in 2005

- Load will remain unchanged. Why?
  - Gas costs for customers will remain relatively high
  - Many large customers have fuel switching capabilities
  - Stronger Canadian dollar and decreased competitiveness in export markets



Note: Industrial & Transportation includes Rates 5, 7, 22, 25, & 27; excludes Burrard Thermal & TGVI.

Total TGI Load



Note: excludes Burrard Thermal & TGVI.

2005 PBR Cost Drivers

Tom Loski

2005 Revenue Requirement

Terasen Gas

Cost Drivers

	2003 Actual	2004 Projected	2005 Forecast
Customer Additions		11,412	10,144
Customers – End of Year	775,516	786,928	797,072
Average Customer Count	770,624	779,498	790,385
Change in Average Customers		8,874	10,887
Customer Growth Percentage		1.15%	1.4%
B.C. Inflation			2%
Adjustment Factor – 50% of CPI			1%

2005 Revenue Requirement

Terasen Gas

Formula Based Capital Expenditures

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

2005 Revenue Requirement

Terasen Gas

Total Plant Additions

	2004 Update	2005 Forecast
Base Capital Expenditure	$91,453	$90,611
Add: WIP Changes	344	(137)
Add: AFUDC	908	919
Add: Overhead Capitalized	26,009	26,335
Total Base Capital Additions To Gas Plant In Service	**118,714**	**117,728**
CPCN Completed in Previous Year & Added to Opening GPIS	14,075	53,749
Total Plant Additions	**$132,789**	**$171,477**

2005 Revenue Requirement

Utility Rate Base

	2004 Approved	2005 Forecast
Net Plant in Service, Mid-Year	$2,190,507	$2,280,774
Other Rate Base Items	109,359	114,984
Utility Rate Base	**$2,299,866**	**$2,395,758**

- 2005 Net Plant in Service forecast includes Coastal Facility Assets of $50.3M, a transfer from operating lease to rate base item due to accounting change.
- Among Other Rate Base Items, Gas Storage increased significantly as a result of higher gas cost.

2005 Revenue Requirement

O&M Expenses

<u>2005 O & M Formula</u> :

- [2004 Adjusted O&M X (1+customer growth) X (1+ CPI – adjustment factor)] + Pension & Insurance Adjustment
- Gross 2005 O &M = [$186,089 X (1+1.40%) X (1+2% -1%)] + $11 =$190,586
- Gross 2005 O & M — $190,586

Gross 2005 O & M	$190,586
Capitalized Overhead	(26,335)
Fort Nelson O & M and Vehicle Lease	(2,522)
Net 2005 O&M	$161,729

*** put detail reference to advance materials**

2005 Revenue Requirement

Terasen Gas

Formula Calculation of O&M

Description	Actual 2003	Approved 2004	Change	Adjusted 2004	Change	2005
Average Number of Customers	770,624	777,779	8,874	779,498	10,887	790,385
Percentage Growth in Average Customers			1.15%		1.40%	
Annual Inflation Rate - CPI			1.70%			2.00%
Adjustment Factor			0.85%			1.00%
Total Gross O & M Expense		$185,740		$186,089		$190,575
Pension & Insurance Adjustment		2,144		2,144		11
Adjusted Total Gross O&M Expense		$187,884		188,233		190,585
Less: Items Not Subject to Overheads per Settlement		(19,726)		(19,763)		(20,239)
TPIP Not Subject to Overhead		(5,605)		(5,616)		(5,751)
Total O&M Subject to Capitalized Overhead		162,553	301	162,854		(25,990)
Capitalized Overhead at 16%		26,009		26,009		26,335
Gross O&M Less Capitalized Overhead		161,875		162,224		164,251
Less: Fort Nelson O&M & Vehicle Lease		(2,458)		(2,463)		(2,522)
Total Utility O&M		$159,417		$159,761		$161,729

2005 Revenue Requirement

Other 2005 Cost of Service Items

- Property Taxes – reforecast yearly, deferral of variances
  - 2005 forecast of $39.6 million ($0.2 million less than 2004 Approved)
- Depreciation and Amortization
  - Determined based on approved depreciation rates and amortization period.
- Other Operating Revenues
  - Reforecast of all items, except Late Payment Revenues (formula Based)
- Income Taxes
  - LCT rate is reduced from 0.2% to 0.175% based on the announced phase-out schedule
- Debt & Interest Rates
  - Unfunded debt rate is set at 4% based on current outlook for short-term rates
  - $220 million long-term issue on September 30, 2005 at 6.25% coupon rate
  - Rollover of 2003 mid-term debt issue of $150 million is planned for September 27, 2005
- Return on Equity (ROE)
  - 9.15% is used in Annual Review advance materials, BCUC generic mechanism for 2005 is 9.03%.

Accounting & Tax Matters

Coastal Facilities Project – Variable Interest Entity

- Originally, a synthetic lease structure was set up to finance Coastal Facilities Project, to achieve significant benefits to customers, while doing no harm to shareholders due to the off-balance sheet nature of financing.
- Benefit achieved to-date amounts to $6 million.
- By BCUC Order No. C-14-98, BCUC assured that “the Company shareholders will be protected from the impact of changes to the current accounting and tax rules” and “if it is not feasible to renew the lease agreement, the outstanding costs of the Project may be financed as a traditional rate base item.”
- In June 2003, a new Accounting Guideline AcG-15 was issued to mandate the Consolidation of Variable Interest Entities. Accordingly, the synthetic lease to Finance Coastal Facilities project will need to be recorded in balance sheet effective January 1, 2005.
- Company will transfer to rate base at January 1, 2005 an estimated $50.3 million representing outstanding balance of the Coastal Facilities project, and fund the assets with a conventional mix of 67% debt and 33% equity.
- As a result, TGI anticipated 2005 revenue requirement to increase by approximately $1.1 million.

Accounting & Tax Matters

B.C. Corporate Capital Tax

- Company is undergoing a CCT audit for years 1995-2002
- Total estimated potential liability for years 1995 to the present including interest, penalties, and other cost associated with reassessment is now roughly $3.5 million
- While the Company will defend its filing position with respect to the various issues, TGI have received BCUC's approval to collect in a deferral account the costs of the appeal process and the amounts of any net assessments owing. (Decision February 4, 2003). The measurement costs are being amortized over three years commencing in accordance with the BCUC decision.

Accounting & Tax Matters

Exogenous Factors

- Ontario Securities Commission (“OSC”) Certification Compliance Costs
  - M152-109 issued to improve the quality and reliability of reporting disclosures
  - Estimated cost: $433,000 for 2004 and $421,000 for 2005
  - Propose to defer 2004 cost and amortize fully in 2005; defer 2005 cost and amortize fully in 2005
- BCUC Levies
  - Actual 2004 BCUC levies exceeded the amount provided for in 2004 rates by $196,000
  - Propose to defer in 2004 and amortize fully in 2005

Accounting & Tax Matters

Customer Deposits

- Tariff requires the Company to pay interest on Customer Security Deposits at prime interest rate minus 2%. The annual interest paid to customers of about $100,000 was never part of past revenue requirement. (historically Customer Deposits are at $2.5-3.0 million level).
- Due to the increase in commodity prices, Company has experienced a significant increase in the number of lockoffs and corresponding increase of Customer Deposits. For 2005, it is forecast to be $23 million on average. Therefore, TGI proposes to establish a regulatory mechanism to recover the interest expense.
- Two options have been identified:
  - Keep $23 million in a separate bank account and have it self funding. There will be no impact on existing customers or shareholders.
  - Use the $23 million as a substitute in place of short-term borrowing requirements from traditional financial markets. Existing customers will benefit from a source of working capital cheaper than through traditional source. And shareholders will not be negatively impacted. Therefore, TGI recommends this option.

2005 Accounting & Tax Matters
Cost Recovery of SAP Assets from TGVI

OPTIONS Considered

1. *TGI to charge TGVI a management fee equivalent to ownership of the $2.4 million in rate base as though TGVI had owned it. No notional transfer is required.*

2. *TGVI to include in its annual revenue requirement calculation the cost equivalent to ownership of $2.4 million SAP asset, categorize as a lease expense. TGVI to reimburse TGI for the use of the asset via a lease expense fee. TGI to include the $2.4 million asset in rate base.*

3. *TGI notionally transfer $2.4 million to TGVI and have TGVI include in its rate base. TGVI to reimburse TGI for the use of the asset via a non-utility management fee. TGI to exclude the $2.4 million asset from rate base.*

Note – all of the above options have TGI retaining legal ownership of the $2.4 million SAP asset

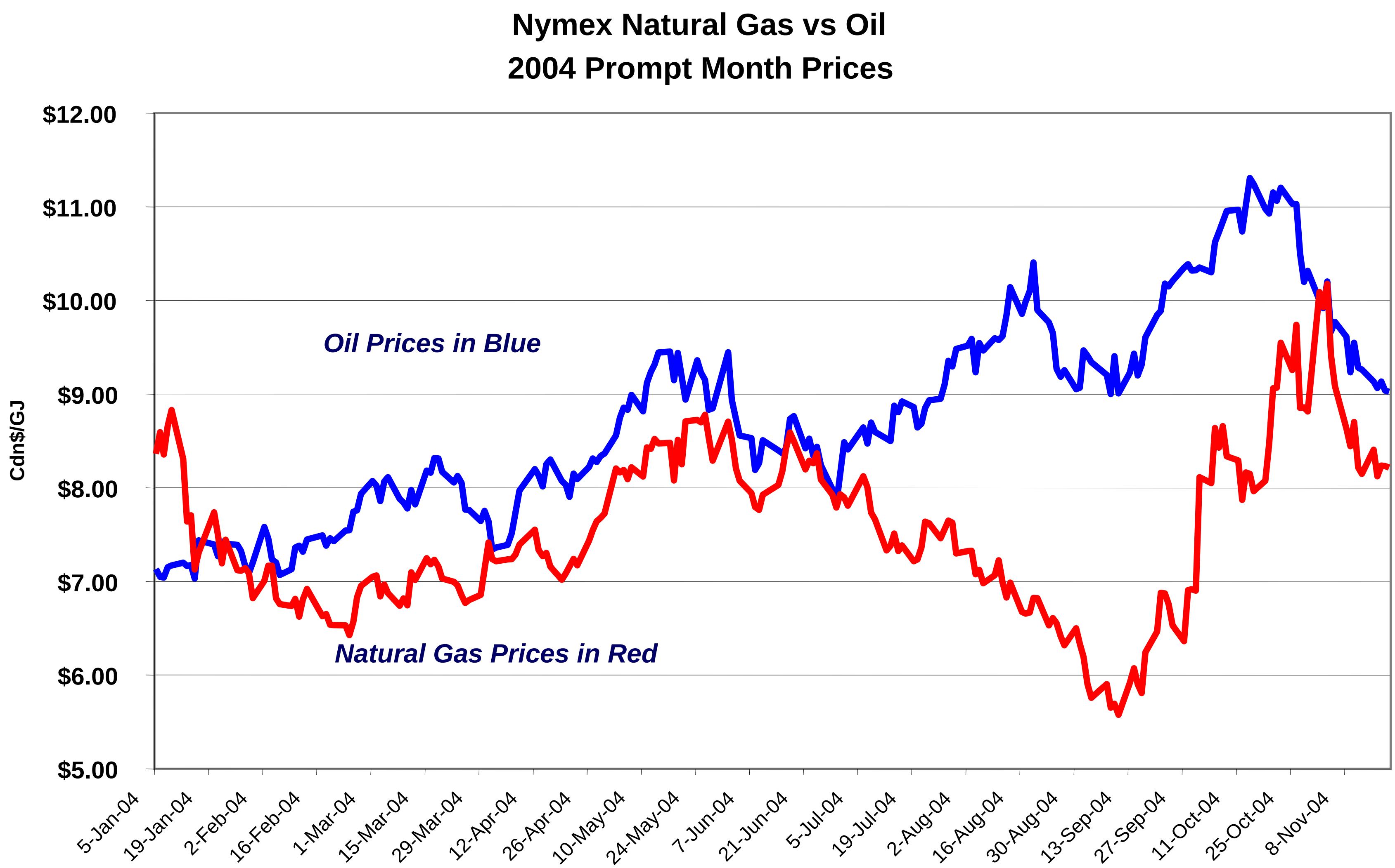
2005 Accounting & Tax Matters
SAP Cost Recovery - Recommendation

- *The optimal solution is Option #2 – for TGVI to include in its annual revenue requirement an operating lease expense equivalent to the revenue requirement associated with ownership of the assets had the asset transfer taken place. Most transparent and avoids potential perceived transfer pricing issues.*
- *Consistent with the common shared technology platform theme*
- *Preserves the nature of the costs associated with the rate base of the assets as they are utilized and allows for efficiency sharing with customers of TGI should any efficiencies exists*
- *Operating lease expense categorized similar to rent for the compressor lease equipment so TGVI will not be adversely impacted by the negotiated settlement O&M mechanism*

Note – all three options require TGVI to reimburse TGI $451,000 in 2004 for the use of the SAP assets

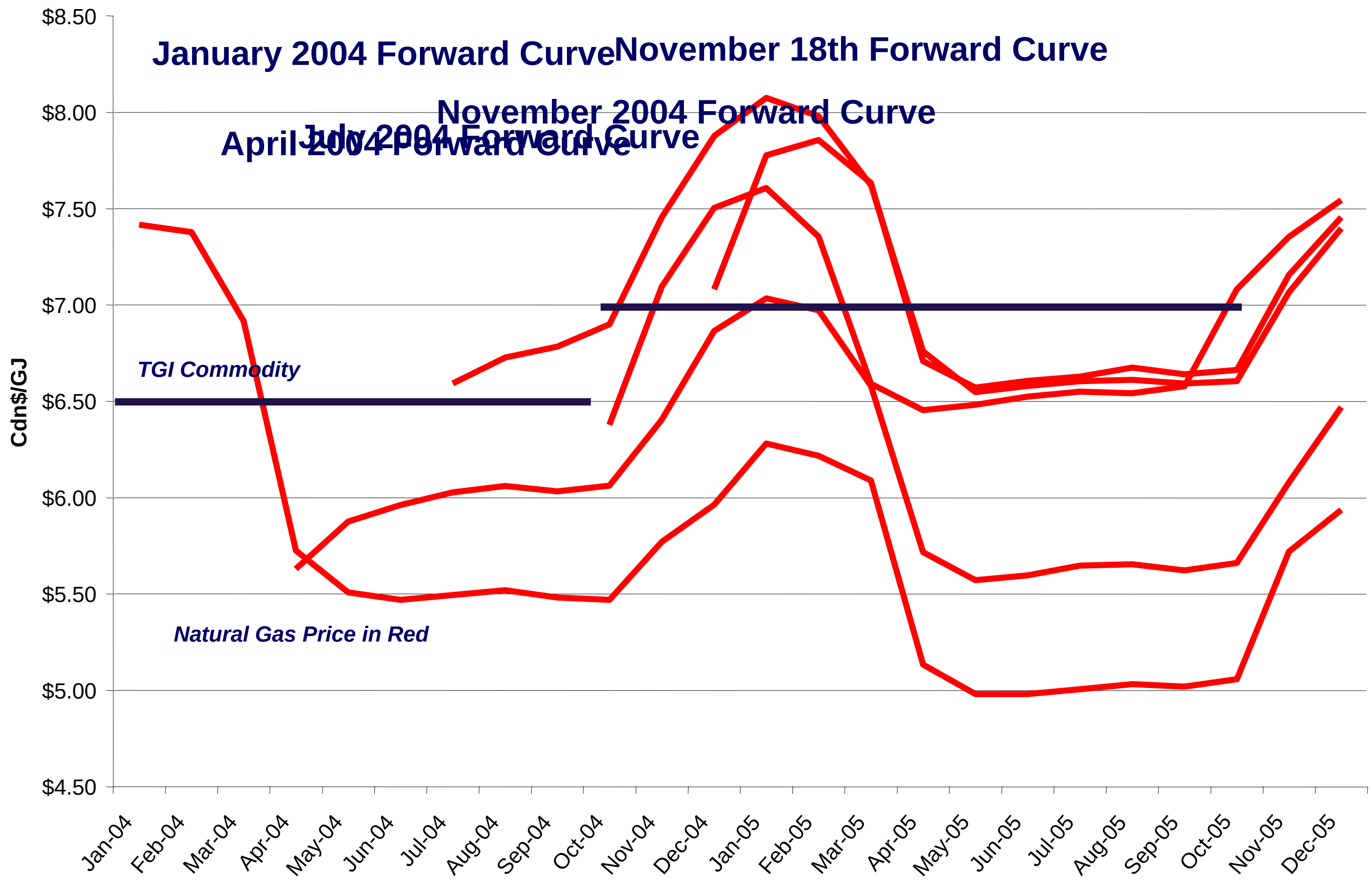
2005 Revenue Requirements & Rate Outlook

Relationship Between Oil & Gas Prices



Natural Gas Price Impact on TGI Rates

Terasen Gas



2005 Revenue Requirement

Summary of 2005 Rate Decrease

(ROE = 9.03%)

		($ Millions)
Volumes/Revenue Related		
■ Higher weighted average use rates for Rates 1/2/3/23	($0.5)	
■ Customer Growth and Industrial Revenue Changes	(4.2)	($4.7)
O&M Related		
■ Higher O&M per formula	4.1	
■ Change in Pension and Insurance forecast	(1.8)	2.3
Other Items		(0.7)
Sub-total		(3.1)
Accounting Change – Coastal Facilities Lease		1.1
Change of SAP Asset Leasing Treatment		0.4
Exogenous Items – OSC Certification and BCUC Levies		1.0
Total Revenue Surplus at ROE of 9.15%		(0.6)
Additional Revenue Decrease due to lower ROE (9.15% to 9.03%)		(1.5)
Total Revenue Surplus at ROE of 9.03%		($2.1)

2005 Revenue Requirement

Terasen Gas

Summary of 2005 Rate Decrease

(ROE = 9.03%)

Line No.	Particulars	2004 Approved	2005 Core	2005 Non-Core	2005 Bypass and Special Rates	2005 Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RATE CHANGE REQUIRED						
2							
3	Gas Sales and Transportation Revenue,						
4	At Prior Year's Rates	$1,380,301	$1,319,679	$56,590	$12,768	$1,389,037	$8,736
5							
6	Add - Other Revenue Related to SCP Third Party						
7	Revenue / Terasen Gas (Vancouver Island)	12,845	0	0	15,991	15,991	3,146
8							
9	Total Revenue	1,393,146	1,319,679	56,590	28,759	1,405,028	11,882
10							
11	Less - Cost of Gas	(923,993)	(907,040)	(1,521)	(363)	(908,924)	15,069
12							
13	Gross Margin	$469,153	$415,696	$55,069	$28,396	$496,104	$26,951
14							
15	Revenue Deficiency (Surplus)	$19,150	($1,860)	($248)	$0	($2,108)	
16							
17	Revenue Deficiency (Surplus) as a % of Gross Margin	4.08%	-0.45%	-0.45%	0.00%	-0.42%	
18							
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.37%	-0.14%	-0.44%	0.00%	-0.15%	

2005 Revenue Requirement

RSAM Update

	$ Millions
2004 Projected RSAM Activity	
■ New RSAM additions	$9.8
■ RSAM Rider recovery	(14.2)
RSAM balance decrease (After Tax)	($4.4)

- For the 10 months ended October 31, 2004, weather in the Terasen Gas service territory has been 7% warmer than normal and about the same as the comparable period in 2003.
- RSAM rider projected to decrease by $0.052/GJ based on 3 year amortization

2005 Overall Customer Rate Impacts

- Total **revenue requirement** decrease of $2.1M results in 0.42% decrease in Gross Margin and 0.15% decrease in total revenue at existing rates. For Lower Mainland residential customers, the delivery rate will decrease by $0.018 per gigajoule.
- **RSAM** rider is expected to do down from 2004 level by $0.052 per gigajoule
- The **ESM** Rider is projected to be a recovery of $0.002 per gigajoule due to earning deficit sharing as determined in accordance with the 2004 earnings sharing mechanism.
- Overall, the residential customers annual bill will decrease by $7.48, or 0.6% of annual cost.

Customer Bill Impacts

Customers	Rate Decrease	Bill Reduction per Annum	% Bill Decrease of Previous Annual Bill
Residential	$0.068	$7.48	0.58%
Small Commercial	$0.065	$19.50	0.59%
Large Commercial	$0.062	$204.60	0.62%
General Firm	$0.008	$92.80	0.09%

OTHER INFORMATION PERTAINING TO THE 2004 – 2007 PBR SETTLEMENT

Terasen Gas Inc.
2004 Annual Review

Nov. 19, 2004

Ron Jupp
Vice President - Distribution

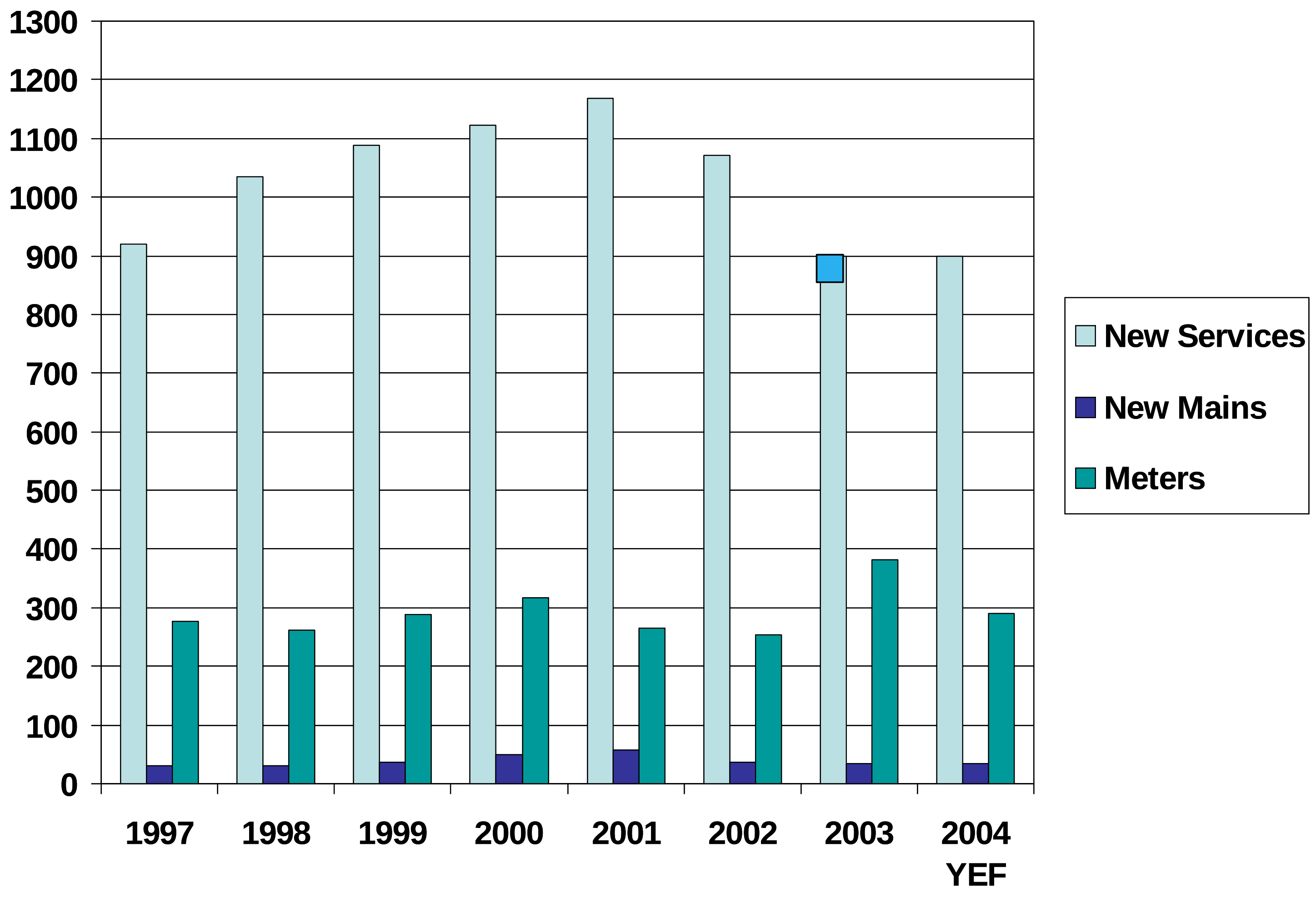
Customer Driven Capital 2003 – 2009:

	2003	2004E	2005	2006	2007	2008	2009
Forecast Customer Additions	**5,538**	**11,400**	**10,144**	**10,293**	**9,405**	**9,132**	**9,478**
Customer Driven Capital Dollars	**2003**	**2004E**	**2005**	**2006**	**2007**	**2008**	**2009**
Mains	4.2	4.7	5.1	5.4	5.0	5.0	5.4
Services	10.1	10.3	9.4	9.8	9.2	9.3	9.9
Meters – Customer Additions	3.0	3.3	3.0	3.1	2.9	2.9	3.0
	17.3	**18.3**	**17.6**	**18.3**	**17.2**	**17.2**	**18.3**

Stated in Millions of Dollars ($)

Reference Section B-1-page 5

Historical Customer Additions Unit Costs



Customer Driven Capital

Contributing Factors to Unit Cost Reductions:

- Optimized excavation equipment: dependent backhoes and mini-excavators
- Use of 2 person vs 3 person crews with equipment
- Establish Core crews and Install crews: reduced the disruption of emergencies.
- Economies of scale - increased activities.
- Nature of the work mix; new subdivisions vs infill projects
- Contractors handle increased workload: jobs are not interrupted.
- Jan 2003 Order Fulfillment implementation reduced costs in new services & mains.
- Mgmt consolidation 2001-2004

Other Regular Capital 2003-2009 - Cost Projections

Terasen Gas

Other Regular Capital	2003	2004E	2005	2006	2007	2008	2009
Meters – Replacement	14.5	14.1	14.8	15.2	15.7	16.2	16.8
System Integrity & Reliability							
Transmission Plant	11.4	8.7	5.4	5.1	5.9	6.1	4.7
Distribution Plant	13.8	12.6	11.9	16.9	9.0	9.2	7.5
Other Capital							
Non- IT	13.2	11.3	11.4	11.7	11.9	12.2	12.5
IT	10.3	8.5	10.2	13.5	13.8	14.2	14.5
Other Regular Capital	**63.2**	**55.2**	**$53.7**	**62.3**	**56.4**	**57.8**	**56.0**
Total Customer Driven & Other Regular Capital	**80.5**	**73.5**	**71.3**	**80.6**	**73.6**	**74.9**	**74.3**

Stated in Millions of Dollars ($)

Reference Section B-1-page 5

Major Capital Projects 2005-2009
Scheduling & Cost Projections

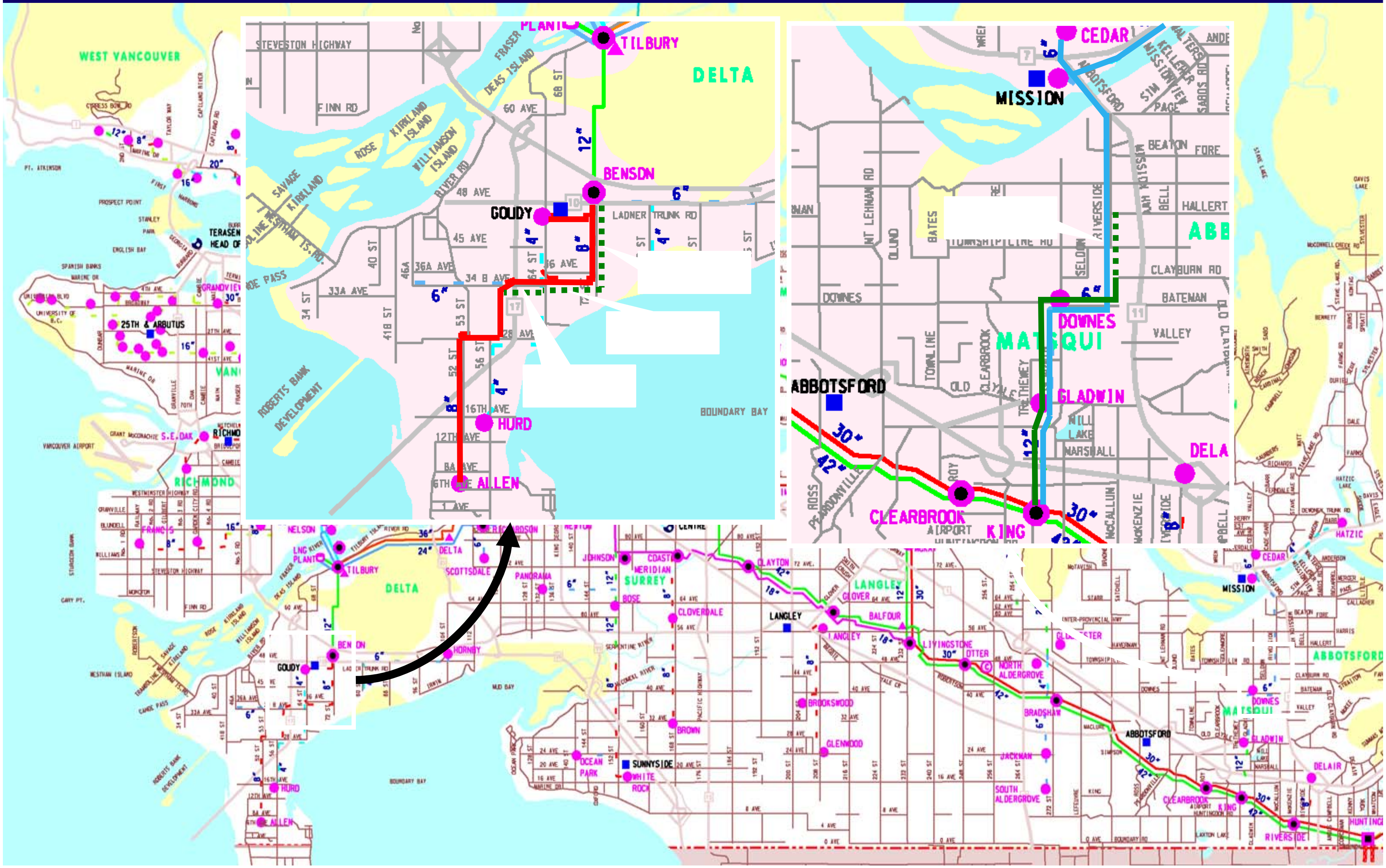
Terasen Gas

Other Regular Capital	2005	2006	2007	2008	2009
Transmission and Distribution Plant					
Secondary Containment	2.1	2.4			
Riverside Road, Abbotsford		1.1			
72nd St to 36th Ave, Delta		1.8			
Goudy Road and 36th Ave, Delta			1.2		
34B to 57th Ave, Delta				1.0	
	2.1	**5.3**	**1.2**	**1.0**	**0**
Non- IT and IT					
SAP Core Application Upgrade	.5	2.0			
SCADA System Upgrade		1.5			
	.5	**3.5**	**0**	**0**	**0**

* Stated in Millions of Dollars ($)

Reference Section B – 1 – page 3 & 7

Major Capital Projects – System Maps



Major Capital Projects Subject to CPCN – Cost Projections

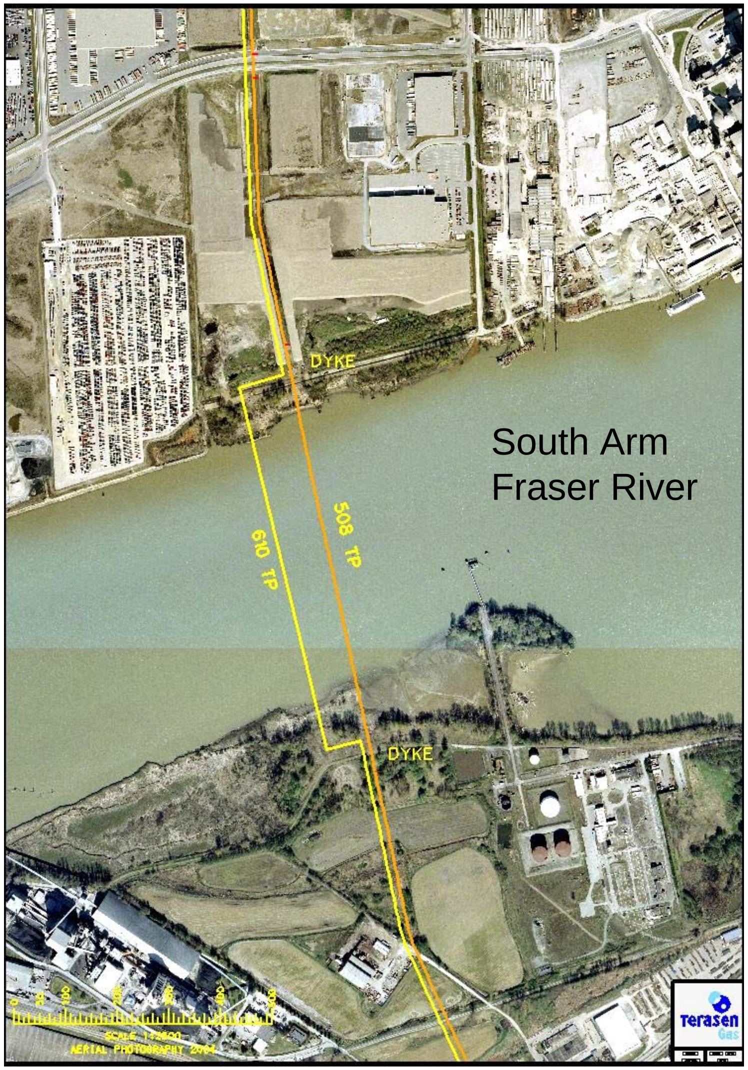
CPCN Applications	2005	2006	2007	2008	2009
Transmission Pipeline Integrity Plan (TPIP)	3.7				
Fraser River Crossing, Vancouver	20.0				
	23.7				

Stated in Millions of Dollars ($)

Reference B -1-page 7)

Fraser River Crossing – System Map

North



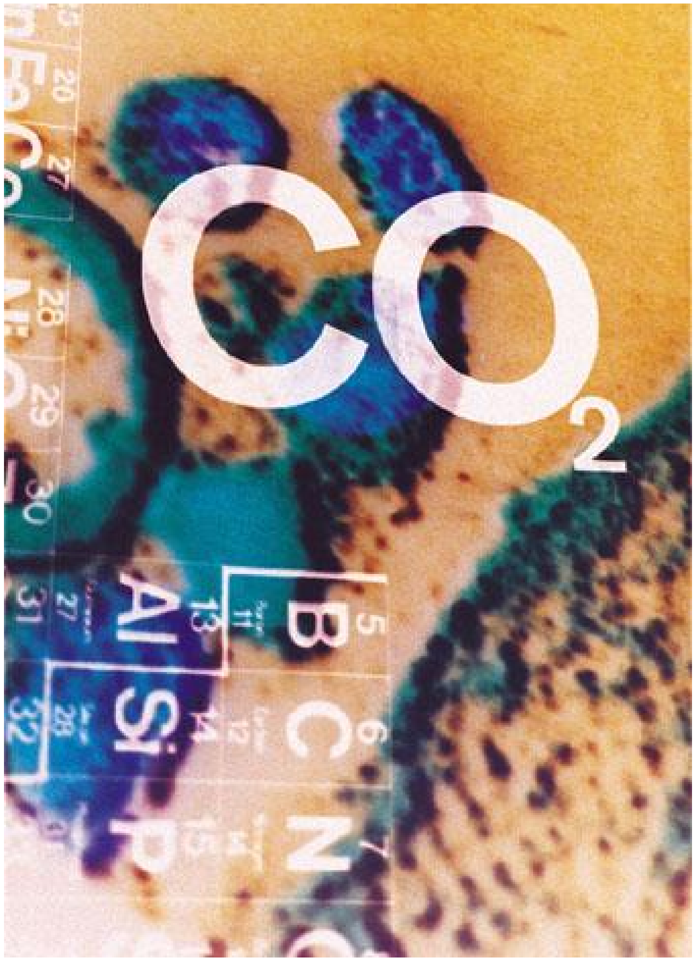
Tilbury LNG Plant
Approx. 1.2 km.

Triple Point Project

Meter Testing Facility Enhancement

David Zerr
VP Operations Governance and Human Resources
November 19, 2004

What is the Impetus for Development of Triple Point?



- Measurement Canada is aware of the potential error (up to 5.5%) that can result from high volume meter tests performed at ambient pressure.
- The Terasen Measurement Group in Penticton has invented a new low cost medium pressure technique that will meet the soon to be imposed MC regulations for the testing of high pressure, high volume meters.
- Compliance costs would be a flow through under PBR
- Our commitment was to bring opportunities of this nature to stakeholders

Capital Expenditures ($ Millions)

Triple Point facility	$ 1.6
IT Software	$ 0.1
Site & building preparation	$ 0.1
	$ 1.8

- Recovery of maximum value for customers is best served by a separate regulatory construct extending beyond the term of the current PBR

Value for Terasen Gas Customers

- Customer value is created by avoiding higher costs associated with outsourcing this activity and by generating additional 3rd party revenues
- Upside on assumed third party meter volumes (conservative) accrues to Terasen Gas customers and shareholders
- Realize scale economies by combining Utility and 3rd party testing in Penticton
- Projects such as Triple Point encourage Terasen Gas Management to devise and implement innovative and cost competitive solutions that deliver value to customers
- A proposed regulatory construct for Triple Point will be filed before the end of Q1 2005 with the BCUC

Proposal for EMS Revenue Incentive

2005 Core Market Admin Incentive Proposal

- **Gas Supply EMS Revenue: Profit Sharing Methodology**
  - Gas Supply staff and resources utilized to provide gas management services to third parties for profit.
  - Profits shared between core customers and shareholders similar to PBR incentive (50/50 sharing).

Projections

2005 gross Gas Supply EMS revenue:	$274,200
2005 Gas Supply EMS Cost of Service:	$135,000
2005 net Gas Supply EMS revenue:	$139,000
Lock 50% customer share as 2005 offset to core market admin (reduction of cost of gas)	$ 70,000
Remaining balance to be shared 50:50	$ 69,000

- Net revenues beyond projections to be shared 50/50.

Shared Services Agreement

- Contract effective January 1, 2004
- Description of services to be provided by Terasen Gas Inc. to Terasen Gas (Vancouver Island) Inc.
- Term of agreement is one year, subject to annual renewals and renegotiations for changes in services provided
- Common costs are shared according to the application of 2 primary cost drivers
  - # of employees
  - # of customers

Code of Conduct &Transfer Pricing Policy Compliance

Doug Cruickshank

Code of Conduct &Transfer Pricing Policy Compliance

- Objectives
  - To meet the requirements of the Code of Conduct and Transfer Pricing Policies approved by the BCUC
  - To ensure business processes and internal controls are in place to facilitate and support compliance with these Policies

Reports on Code of Conduct &Transfer Pricing Policy Compliance

- Two significant compliance reviews conducted in accordance with the Negotiated Settlement
  - Annual Internal Audit Report
  - Review of External Auditors for 2004

Code of Conduct &Transfer Pricing Policy Compliance

- Internal Audit Services Scope and Approach
  - Generally accepted standards for review engagements, as per the Canadian Institute of Chartered Accountants
  - Procedures relate to requirements regarding sharing of customer information, cross charging time to Non-Regulated Businesses for services performed and special arrangements provided to Terasen Gas Inc. customers by Non-Regulated Businesses
  - Procedures include:
    - Enquiries and discussions with relevant personnel
    - Check of accounting information
    - Tests of processes and internal controls
    - Random survey of employees on compliance

Code of Conduct &Transfer Pricing Policy Compliance

- Opinion of Director, Internal Audit Services

"Based on my review, nothing has come to my attention that causes me to believe that Terasen Gas Inc. is not in compliance with the Code of Conduct and Transfer Pricing Policy for the period January 1, 2004 to August 31, 2004."

Signed:

Doug Cruickshank, Chartered Accountant
October 8, 2004

Code of Conduct &Transfer Pricing Policy Compliance

- Independent External Auditor's Report (2004-2007 PBR Settlement)
    - KPMG LLP
    - External auditors to review work performed by Internal Audit Services
    - External auditors will provide a report of Terasen Gas Inc's compliance with the Code of Conduct and Transfer Pricing Policy consistent with section 8600 of the CICA Handbook "*Review of Compliance with Agreements and Regulations*".

Code of Conduct &Transfer Pricing Policy Compliance

- KPMG LLP Compliance Review
  - Reviewed TGI Compliance with CoC and TPP for the eight month period ended August 31, 2004, including review of Internal Audit working papers and report

"…**based on our review, nothing has come to our attention that causes us to believe that the Company is not in compliance with the Transfer Pricing Policy and Code of Conduct referred…"**

Signed:

KPMG LLP, Chartered Accountants
October 28, 2004

Wrap Up