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August 14, 2009

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, BC
V6E 2N7

Attention: Mr. James L. Quail, Executive Director

Dear Mr. Quail:

Re: Terasen Gas Inc. ("Terasen Gas")
2010 and 2011 Revenue Requirements and Delivery Rates Application

Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization et al ("BCOAPO") Information Request ("IR") No. 1

On June 15, 2009, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-89-09 setting out the Regulatory Timetable for the Application, Terasen Gas respectfully submits the attached response to BCOAPO IR No. 1.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachment

cc (e-mail only): BCUC and Registered Parties

1.0 Reference: Executive Summary, Part I, p. 1

The evidence states that "[t]he increase sought for 2010 is 5.3 per cent, with an additional effective base rate delivery increase of 4.1 per cent (cumulative increase of 9.4 per cent) in 2011.

1.1 Please provide comparative figures for 2010 and 2011 assuming that all other TGI applications currently before the BCUC are approved as proposed by TGI.

Response:

If the Return on Equity and Capital Structure and Revenue Requirement Applications currently before the BCUC are approved as filed, the combined impact on rates is an increase of approximately 13.8 per cent in 2010 and an additional increase of 3.8 per cent in 2011 (cumulative increase of 17.6 per cent). The Customer Care Enhancement CPCN Application will not affect rates until 2012; it is expected that this application will have a minimal impact on 2012 rates.

2.0 Reference: Executive Summary, Part I, p. 3

The evidence states that "TGI's competitive position in B.C. continues to decline with increases in natural gas prices and the gradual erosion of the cost advantage of natural gas over electricity. ... [a]ll else equal, reduced demand for natural gas puts upward pressure on revenue requirements and delivery rates."

2.1 Please provide estimates of the income elasticity of demand for natural gas and electricity in B.C. If these estimates are not known for B.C., please provide North American estimates.

Response:

Although TGI has attempted to estimate the income elasticity of demand for natural gas, the results did not seem reasonable. Through regression analysis, where the natural log of annual consumption per customer and the natural log of income was analyzed, the results indicated that there was an inverse relationship between income and demand for natural gas. That is, the results indicated that increases in income levels would result in declines in demand for natural gas. For this reason, TGI does not believe the results of their analysis are reasonable.

For North America in general, as indicated in the Attachment 2.1 entitled "Natural Gas Demand Elasticity" which was presented during the Southern Gas Association's Fall Leadership Conference in 2006, the intermediate-term and long-term income elasticity's of demand for natural gas are 0.27 and 1.14, while the intermediate-term and long-term income elasticity's of demand for electricity are 0.62 and 0.79.

2.2 Please provide the maximum commodity price for natural gas for which gas would be competitive with electricity in 2010 assuming TGI's delivery rates are approved as proposed and assuming that electricity prices in B.C. in 2010 are equal to 2009 prices.

Response:

It is important to note, however, that there are many competitive factors in addition to price that influence a customer when making a fuel choice. A home with natural gas needs to have an operating cost advantage in order to recoup the difference in initial capital costs of installing natural gas equipment versus electricity for space heating. Although natural gas commodity prices are relatively low currently, significantly higher prices and price volatility are in recent

memory. Public discussion of climate change and the need to implement carbon taxes or cap and trade regimes to reduce GHG emissions is a commonplace. This is further compounded by the public perception that BC Hydro electricity supply is an "all green solution". TGI believes that perceptions are often as much an influence in public behaviour with respect to energy use as reality is. Also, in the new construction market, developers, that do not benefit themselves from the lower operating costs of a natural gas heating system, will often decide against installing gas because they are uncertain of whether they will be able to recover their additional upfront capital costs in the selling price of a home. So even if it appears that there is a large operating cost differential a gas heating system may not be installed.

Based on an annual BC Hydro residential electric bill of $1,641 (as per Figure A-4 Part III: Section A – Tab 1: External Situational Context Page 60, which is based on an annual residential consumption of 95 GJ, a calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% and inclusive of the applicable 1% rate rider), and holding the current Midstream charge per GJ inclusive of rate rider 9, a cost of gas charge per GJ of $11.64 would yield an estimated annual bill of approximately $1,641, based on an annual residential consumption of 95 GJ. It is not unreasonable to forecast that commodity costs may rise in the future making a cost of gas charge per GJ of $11.64 a possibility. On October 1, 2005, TGI flowed through a cost of gas charge of $9.292 per GJ, reflecting the steep increase in natural gas commodity market rates, largely in part due to Hurricane Katrina.

2.3 Please explain how reduced demand for natural gas puts upward pressure on revenue requirements.

Response:

Reduced demand for natural gas leads to reduced consumption levels on the natural gas system. This decline in throughput volume leads to a higher unit cost for delivery service so that the revenue requirement total costs can be recovered from customers, all other factors being equal. From a total cost point of view, TGI has upward pressure on costs in some areas of the company to deal with the changing environment in which TGI operates. It is TGI's conclusion that taking a "do nothing" approach to try and address these challenges is not in the best interest of the TGI customers in the long term. Thus, TGI feels that it is reasonable and necessary to incur these incremental costs despite a decline in demand for natural gas.

3.0 Reference: Part III, Section A, pages 56 and 60 (Figure A-4)

The evidence states that "Terasen Gas' competitive position relative to peers and competitors continues to decline, presenting further challenges that we must meet."

3.1 Please explain how the data presented in Figure A-4 supports this statement.

Response:

Figure A-4 demonstrates that, with the exception of Gaz Metro, TGI does not share the same price advantage as its Canadian peers, Direct Energy-Atco Gas, Union Gas and Enbridge Gas. All three of these utilities do not compete against lower priced hydro electricity (as TGI and Gaz Metro do). As outlined in the response to BCOAPO IR 1.2.2, there are many competitive factors in addition to price that influence a customer when making a fuel choice.

3.2 Please indicate whether TGI considers Gaz Metro a peer.

Response:

Yes, TGI considers Gaz Metro a peer in a general sense. One key factor that is displayed in Figure A-4 is the competitive position that the natural gas utility has against its electric competitor. In this sense TGI faces similar challenges as does Gaz Metro.

4.0 Reference: Executive Summary, Part I, p. 8

The evidence states that "[s]avings have been achieved in both O&M and capital expenditures, resulting in depreciation savings and rate base reductions. Total earnings available for sharing during the PBR Period are expected to be close to $138 million, of which an estimated $69 million benefit will have accrued to customers. ... This has been achieved despite the actual labour inflation during the PBR period ... being a full percentage point higher than the average Consumer Price Index ("CPI") from the Annual Reviews ... ."

4.1 Please indicate whether any of the PBR Period savings were due to deferred capital expenditure or deferred maintenance or replacement, including less frequent or less extensive inspections, leak surveys, etc. Please provide specifics.

Response:

For O&M, please refer to BCUC IR 1.75.1 and 1.77.1.

For Capital, please refer to BCOAPO IR 1.30.1.

4.2 Would it be fair to say that had TGI pursued the same productivity initiatives under a cost of service regime as it did under PBR, that ratepayers would have saved $138M over the PBR Period?

Response:

In a traditional regulatory model, all expenditures (O&M and Capital) that are above or below the approved budgeted amounts as dictated by the governing regulatory body are to the benefit or cost of the Company and its investors absent of any deferral account to capture variances. Ongoing cost savings are, however, reflected in the following year's cost of service, resulting in customers benefiting (all else equal) from adjusted rates in that year.

TGI considers the premise of the question that $138 million in savings would have been achieved absent the PBR to be speculative. The PBR agreement that has been in place was unique and was put in place to better align the interest of the customers and the Company and incent appropriate reductions wherever possible. The benefits described in the Application that were shared between the customers and the Company between 2004 and 2009 are real benefits that flowed from the structure of the PBR. TGI reported to intervenors and the Commission on the results of the PBR annually. TGI does not believe anything can be gained

in this Application from revisiting the terms of the PBR, to which the parties, including BCOAPO, agreed and which was approved by the Commission on two separate occasions.

4.3 Please identify any savings made during the PBR Plan period due to pre-PBR costs being fully amortized during the PBR period, tax changes implemented during the period, expiration of pre-PBR Plan period programs, direct and indirect regulatory costs, changes with respect to depreciation rates and/or CCA policies, or others due to the loosening of exogenous constraints, laws, or regulations.

Response:

The response to this question has been broken down into six subheadings:

1. Deferred Charges (pre-PBR costs full amortized during the PBR Period)
2. Tax Rate Changes
3. Regulatory Costs
4. Depreciation Rate Changes
5. CCA Changes
6. Exogenous Factors

Deferred Charges

The following is a list of Deferred Charges that had been approved by the Commission in or prior to 2003 that had a balance at the start of the PBR period and were fully amortized during the PBR period:

Particular	Jan. 1, 2004 Balance $000's	Year Fully Amortized
Market Rebate Incentive – Water Heater Grants	$8	2004
BC Hydro Service Agreement Costs	471	2004
Coastal Facilities – Noncapital Finance Costs	362	2004
ABC T Project Requirements Phase	30	2004
2001 Rate Design	115	2004

Particular	Jan. 1, 2004 Balance $000's	Year Fully Amortized
Coastal Facilities - Relocation	683	2005
Coastal Facilities – Fraser Valley NBV Amortization	419	2005
Burner Tip Services	(6)	2005
Demand Side Management DRIA	(391)	2006
Coastal Facilities – Extraordinary Plant Loss Lochburn	97	2007
Overheads Change – Income Tax Refund	(554)	2007
CIAOC Software Tax Savings / OH Change	(3,231)	2007
Deferred 2000 SCP Cost of Service	254	2007
CCT	(531)	2007
2003 Revenue Requirements	272	2008
2004-2008 Revenue Requirements	113	2008
NGV Compression Equipment Recovery	1,278	2009
SCP-PG&E Contract Cancellation	889	2009
Total	$278	

The amortization of the deferral balances included in the table above would have been forecast and included in the rate setting process as part of each year's Annual Review during the PBR Period. As a result, these amounts would not have contributed to savings (earnings sharing) during the PBR Period.

Tax Rate Changes

The following is a list by year of the income tax rate, Social Services Tax (SST) rate, Carbon Tax, and Ice Levy.

Year	Income Tax	LCT	SST	Carbon Tax [1]		Ice Levy [3]
				Natural Gas	Propane	
2003	37.62%	0.225%	7.5%	N / A	N / A	N / A
2004	35.62%	0.200%	7.5% [2]	N / A	N / A	N / A
2005	34.87%	0.175%	7.0%	N / A	N / A	N / A
2006	34.12%	N / A	7.0%	N / A	N / A	N / A

Year	Income Tax	LCT	SST	Carbon Tax [1]		Ice Levy [3]
				Natural Gas	Propane	
2007	34.12%	N / A	7.0%	N / A	N / A	0.4%
2008	31.00%	N / A	7.0%	$0.49660	$0.60180	0.4%
2009P	30.00%	N / A	7.0%	$0.74490	$0.90270	0.4%

1. Carbon Tax is expressed as a rate per GJ. Rates are effective July 1 each year.
2. On October 21, 2004 the SST rate was changed to 7.0%.
3. The ICE Levy was implemented September 1, 2007.

The Federal Corporate Surtax was eliminated on January 1, 2008, which is incorporated in the income tax rate changes in the table above showing income tax rates. Reductions in the Federal / Provincial tax rates and the elimination of the Large Corporate Tax Rate would not have contributed to the savings because the tax rate changes were incorporated in the annual reviews or in a deferral account. Changes to the PST as it applies to the Company's operating and capital purchases would have contributed to the savings for 2005, but the amount is not determinable. The Carbon Tax and the Ice Levy would not have contributed to savings because these taxes are flow-through items on the customers' bill. For the Carbon Tax and Ice Levy the Company is effectively a tax collector for the provincial government on sales to customers; TGI costs related to the carbon tax were deferred.

Regulatory Costs

The following table contains the direct and indirect regulatory costs in $000's for the following agencies for the years 2003 to 2008:

Year	BCUC	BC Safety Authority / Gas Safety Branch [1]	Oil & Gas Commission	Consumer Affairs (Federal Gov't)
2003	$1,191	$33	$84	$48
2004	$1,577	$36	$93	$82
2005	$1,599	$38	$93	$44
2006	$1,165	$37	$93	$24
2007	$1,074	$38	$92	$36
2008	$1,128	$43	$86	$12

1. Includes an estimated $12,250 for approximately 350 gas fitters gas licenses paid each year.

Payments to the BCUC have been relatively steady at $1.2 million; since BCUC levies were a flow through item during the PBR Period, none of the amounts would have been included in the

determination of the savings. Payments to the BC Safety Authority, Oil and Gas Commission and Consumer Affairs (Federal Government re fees for meters) have also been relatively stable and have provided an immaterial contribution to savings.

Depreciation Rate Changes

From 2003 to 2004 the following Depreciation rates changed:

- Account 474 Meter Installation & Regulators changed from 3% to 3.57%,
- Account 478 Meters changed from 3% to 3.57%, and
- Account 483 Computer Software (Non-Infrastructure) changed from 12.5% to 20%.

The depreciation rates for all other plant accounts remained unchanged; and from 2004 throughout the PBR period the depreciation rates remained unchanged. The savings in depreciation expense were due to the capital efficiency savings and not to any changes in depreciation rates.

CCA Changes

The following table lists changes to CCA classes and CCA rates.

Year / Type of Assets	CCA Class	CCA Rate	New CCA Class	CCA Rate
February 2005				
Transmission Pipeline	1	4%	49	8%
Transmission Compressor Equipment	1	4%	7	15%
March 2007				
Distribution Pipelines	1	4%	51	6%
LNG Equipment	1	4%	47	8%
Non-residential Buildings	1	4%	1.3	6%

Computer Hardware CCA class and rate applicability is as follows:

Class 10 (30%) - acquired before Mar 23, 2004;

Class 45 (45%) - after Mar 22, 2004 and before Mar 19, 2007;

Class 50 (55%) - after Mar 18, 2007; and

Class 52 (100%) - after Jan 27, 2009 and before Feb 2011 (Half year rule does not apply).

The CCA rate changes were included in the Company's Annual Reviews if promulgated before the determination of rates for that year. Any variances between the CCA rates used in determining customers' rates and the CCA rates included in the determination of the Company's achieved ROE were included in the calculation of the Earnings Sharing. Other than the CCA rate changes discussed on page 416 of the Application, such changes have not been material.

Exogenous Factors (Excerpt from TGI 2010-2011 RRA pages 197-198)

During the term of the PBR Period, the Company received special treatment for Exogenous Factors. Customers' rates were adjusted for those exogenous factors that were beyond the control of the Company including: judicial, legislative or administrative changes, orders and directions; catastrophic events, by-pass or other similar events imposed on Terasen Gas which were not reflected in the 2003 base upon which subsequent year's rates were set. Also included in Exogenous Factors were changes in Generally Accepted Accounting Principles, standards and policies. Changes in revenue requirements resulting from directions from the Commission were also to be treated as Exogenous Factors.

Terasen Gas applied for and received Exogenous Factor treatment during the years 2004 to 2009 for:

Government Policy Changes and Legislative Changes

- Ontario Securities Commission Compliance Costs
- PST Reassessment re Southern Crossing Pipeline
- Carbon Tax Implementation
- Olympic Security Costs
- Unforecast annual changes to income tax rates
- Changes resulting from directions of the Commission
- BCUC Levies

GAAP Changes

- Accounting Guideline AcG 15 Consolidation of Variable Interest Entities
- Inventories

- IFRS Implementation Costs

The items that were accorded exogenous factor treatment would not enter into the calculation of sharing; since they were either included in the determination of rates for that year or accorded deferral account treatment.

4.4 Please confirm that if labour rate increases exceed the rate of inflation, then reducing overall operating costs requires using less labour.

Response:

If labour rate increases exceed the rate of inflation, a reduction in overall operating costs can be achieved through a number of different methods, only one of which would be to use less labour. The total O&M cost pool is managed as a whole to achieve O&M targets; savings as compared to the formula are not individually managed by labour vs. non-labour categories.

4.5 Please indicate whether the average CPI from the Annual Reports equals the publicly published CPI. If not, please explain.

Response:

The 2004-2008 average BC CPI from the Annual Reviews of 1.98% is slightly different than the average BC CPI as provided by Statistics Canada of 1.92%[1] for the same period.[2]

Discrepancies between the BC inflation used for the annual review and the published Statistic Canada BC Inflation may exist for several reasons:

- The CPI used for each Annual Review was derived pursuant to the provisions of the Settlement Agreements (Order No. G-51-03 and Order No. G-33-07) and was determined as the average of the forecasts from four reputable industry sources: Conference Board of Canada, B.C. Ministry of Finance, RBC Financial Group and the Toronto-Dominion Bank.

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[1] Annual average of all-items consumer price index for British Columbia
http://www40.statcan.gc.ca/l01/cst01/econ09k-eng.htm

[2] 2009 was excluded from the average comparison because a comparable annual 2009 figure from Statistics Canada is not yet available.

- The CPI used for each Annual Review is a forecast and was not trued up for actual BC inflation.
- The BC CPI as recorded by Statistics Canada for each year is based on the 12 month BC inflation experienced.

5.0 Reference: Executive Summary, Part I, p. 13, Capital Savings and Part III, Section B, p. 190, Table B-1-31

5.1 Please explain how, and relative to what, the "$19.3 million related to capital savings" was calculated.

Response:

Consistent with the PBR agreement and as demonstrated in Table B-1-24 of the Application, the formula capital expenditures were calculated each year based on the prior year amount and adjusted for inflation and an efficiency factor. The formula capital expenditures were embedded in the calculation of the formula net plant in service and correspondingly, the formula rate base.

For the 2010 and 2011 forecasts, the $19.3 million related to capital savings reflects the cost of service impact of rebasing from the formula net plant in service to projected net plant in service. The $19.3 million is comprised of $5.0 million in savings related to the earned return and $14.3 million in savings related to depreciation. The savings were calculated by comparing approved and projected amounts for 2009 and using the applicable tax and return on rate base as demonstrated below:

Line No.	Particulars	Rebase Impact	Reference
	(1)	(2)	(3)
1	Projected 2009 Depreciation Expense*	$ 79.7	- Tab C-13, Schedule 72, Column 5, Line 26 /1000
2	Approved 2009 Depreciation Expense*	89.7	- Tab C-13, Schedule 72, Column 2, Line 26/1000
3	After Tax Rebasing Depreciation Impact	(10.0)	
4			
5	2009 Tax Rate	30.00%	- Tab C-13, Schedule 73, Column 2, Line 11
6			
7	Before Tax Impact of Rebase Depreciation	(14.2)	= Line 3 / (1 - Line 5)
8			
9	Tax Impacts of Rebase Depreciation	(4.3)	= Line 7 - Line 3
10			
11	Projected 2009 Mid Year Net Plant In Service	2,387.3	- Tab C-13, Schedule 74, Column 5, Line 14 /1000
12	Approved 2009 Mid Year Net Plant In Service	2,456.1	- Tab C-13, Schedule 74, Column 2, Line 14/1000
13		(68.9)	
14			
15	Return on Rate Base	7.33%	- Tab C-13, Schedule 72, Column 2, Line 38
16			
17	Earned Return Impact of Rebase Net Plant In Service	(5.0)	= Line 13 x Line 15
18			
19	Total Rebase Savings Attributable to Capital	**(19.3)**	= Line 3 + Line 9 + Line 17
20			
21	*Includes amortization expense. The approved amortization expense is equal to the projected amortization expense; therefore,		
22	any variance is attributable to depreciation expense.		
23			

5.2 Please explain how stakeholders can positively determine that any claimed capital savings were not simply the result of deferred expenditures.

Response:

While the question appears to imply that there are no savings associated with the deferral of capital expenditures, TGI believes instead deferring their timing without jeopardizing the safety and reliability of the system is prudent and appropriate. The same approval process that results in the prudent deferral of capital expenditures also promotes reduced capital spend, which has even greater benefits for customers.

Under the PBR agreement, capital savings realized benefited both ratepayers and the shareholder. Capital savings defined as actual base capital spending compared to that allowed as per approved formula were a function of two factors – the level of allowed base capital spending as determined by the formula and the actual capital spending as managed and determined by TGI management. Based on historical expenditures and specific needs identified at that time, the allowed capital spending developed by TGI was reviewed by intervenors and the Commission and was determined to be an appropriate base level to be applied for the PBR period for the purposes of rate setting.

Over the term of the PBR period, savings were realized primarily in Category B - Distribution and Category C - IT Capital where actual spending was impacted with the introduction of the Capital Management Office. The Capital Management Office was created to exercise a greater level of discipline on capital spending by requiring more formalized business case justification and added rigor in reviewing and approving spending. Representation on the Capital Management Office from all areas of the Company facilitated further vetting of the merits and justification of capital projects, enabling the balancing of business priorities. Today, the Capital Management Office exists in a similar form known as the Utility Operating Committee.

Contributing to the savings realized for Category B – Distribution during the PBR period includes more focused investment for system reinforcements and seismic and system integrity work. As mentioned, this is in part due to the introduction of the Capital Management Office. In addition, the implementation of centralized asset management approach in Distribution contributed further to optimization of asset planning and management, the results of which are reflected in Distribution's five year infrastructure plan. Please refer to page 453 of the RRA for discussion of the planning process. As a result of these changes, forecasted expenditures for 2010 and 2011 in this category of approximately $8 million per year are expected to remain at a level consistent with that observed during the PBR.

Category C - IT spending was lower than that allowed under the PBR as TGI continually assessed and adjusted business priorities and the need for IT investment. Priorities in ensuring a successful restructuring of the company during the USP initiative in 2004/2005 reduced the need for IT investment and limited the resources available from the operating departments to successfully implement the IT projects. However evolving and changing business needs along with increased need to upgrade / replace aging IT infrastructure and applications in recent years have been driving IT expenditures higher from that in the past and will continue to drive IT expenditures higher into 2010 and 2011. TGI will be applying the same level of rigour in scrutinizing and approving IT capital projects as it does today.

TGI's actions during the PBR period in introducing more rigour to scrutinize and prioritize capital expenditures, without compromising the safety and reliability of the system, has resulted in capital savings for the benefit of ratepayers and the shareholder.

5.3 Please provide a comparison between actual PBR Period capital spending and the capital spending as outlined in TGI's last five-year capital plan that was approved before the start of the PBR period.

Response:

Below is a comparison between the base capital spending as outlined in TGI's five year capital plan approved before the start of the PBR period and the actual PBR period capital spending. The total average actual capital expenditures over the 2004 – 2008 period are $78.6 million. This is $4.7 million lower than the $83.3 million total average forecast of the 2004 – 2008 period approved prior to the start of the PBR period.

For the purposes of calculating base capital savings under the PBR formula, the table below is not relevant as PBR capital savings are determined by comparing the formula based approved amount to the actual capital expenditures in each year.

	2004 Forecast	2004 Actual	2005 Forecast	2005 Actual	2006 Forecast	2006 Actual	2007 Forecast	2007 Actual	2008 Forecast	2008 Actual	Average Forecast	Average Actual
Category A												
Mains	5.8	5.3	5.9	7.4	6.1	8.1	6.4	8.1	6.6	11.0	6.2	8.0
Services	9.9	13.3	10.4	14.6	10.7	16.4	11.1	17.1	11.4	18.0	10.7	15.9
New Meters & Meters Recalled	17.1	15.4	17.5	15.3	18.0	16.2	18.4	13.7	18.9	14.9	18.0	15.1
Total Category A	**32.8**	**34.0**	**33.8**	**37.3**	**34.8**	**40.7**	**35.9**	**38.9**	**36.9**	**43.9**	**34.8**	**39.0**
Category B												
Transmission Plant	12.0	7.1	6.0	5.6	5.1	8.7	5.9	5.1	6.0	13.3	7.0	7.9
Distribution Plant	13.0	11.0	11.3	10.2	16.8	9.7	9.1	10.4	9.2	8.1	11.9	9.9
Total Category B	**25.0**	**18.1**	**17.3**	**15.8**	**21.9**	**18.4**	**15.0**	**15.4**	**15.2**	**21.4**	**18.9**	**17.8**
Category C												
IT	14.9	7.3	16.2	10.6	17.4	7.8	17.9	4.2	18.2	10.5	16.9	8.1
Non-IT	12.2	10.9	12.4	12.0	12.7	16.6	12.9	14.7	13.2	14.2	12.7	13.7
Total Category C	**27.1**	**18.3**	**28.6**	**22.6**	**30.1**	**24.5**	**30.8**	**18.8**	**31.4**	**24.7**	**29.6**	**21.8**
Total	**84.9**	**70.4**	**79.7**	**75.7**	**86.8**	**83.6**	**81.7**	**73.2**	**83.5**	**90.0**	**83.3**	**78.6**

Figures exclude AFUDC and Capitalized Overheads

Notes:
1. Expenditures in $millions
2. Forecast figures are consistent with the Capital Plan in 2004 - 2008 Annual Review filing.

5.4 Please provide copies of all Terasen Gas' five-year (or multi-year) capital spending plans approved during the PBR Plan period and also the most current approved multi-year capital plan.

Response:

Included in Attachment 5.4 are copies of all five-year capital plans that were provided as annual review updates during the PBR period.

6.0 Reference: Introduction, Part II, pp. 16-17, Two-Year RRA

6.1 Please provide any information available pertaining to TGI's accuracy with respect to forecasting costs and revenues (and their drivers) two years into the future.

Response:

TGI's accuracy with respect to forecasting costs and revenues (and their drivers) two years into the future is dependant upon TGI's ability to manage and control that particular revenue, cost or driver.

Revenues as they are somewhat dependent on weather and cost of gas are sometimes difficult to forecast. With costs such as municipal taxes or drivers such as interest rates or tax rates over which the company maintains little or no control, TGI often experiences difficulty with forecast accuracy. In some of these cases, the use of deferral accounts serve to effectively manage rates for customers.

With respect to costs such as O&M, over which the company maintains significant control, TGI's ability to forecast accurately is significantly enhanced. In this case, TGI's budget process is comprehensive with detailed department budgets being prepared both on an activity and resource view. Zero based budgeting, unit costing, historical trending, analysis of pressures and opportunities are techniques employed to increase the degree of forecast accuracy. Throughout the PBR period of 2004 through 2009, O&M per Customer has been a Scorecard Target. During this period average actual results have been within 1% of Target.

With respect to capital, TGI points to its response to BCOAPO IR 1.39.1 outlining significant capital projects completed during the PBR period. For the projects listed which generally had up to a two year completion timeline, all four were completed under the Commission approved amounts.

7.0 Reference: Introduction, Part II, p. 17, Future PBR

The evidence states that "[t]he Company is hopeful that the outcome of this RRA will provide the basis for further discussion about a subsequent multi-year PBR plan."

7.1 Please confirm that any discussion pursuant to the outcome of this RRA must necessarily occur after the two-year period of this RRA, when final results are known and have been reviewed by parties.

Response:

As with any revenue requirements application, the base year for actual costs and revenues must be established before parties can rationalize the changes that would be contained in the application that would cover the next revenue requirements period. It is anticipated that TGI would use the 2010 year end results and the projected year end results for 2011 as the bases for any subsequent multi-year PBR.

7.2 Please indicate approximately how long it would take TGI to prepare pre-filed evidence for a multi-year PBR plan from the time TGI decided to file a PBR application.

Response:

Depending on the scope and the term of the PBR agreement, TGI anticipates it could take any where from three to six months to prepare an application that would form the basis for a PBR agreement based on past experience.

7.3 Does TGI intend on filing an application for a multi-year PBR to start in 2012 or 2013?

Response:

TGI has not yet determined when it may file an application for a PBR, nor which year a PBR plan may commence in. TGI will consider the appropriateness of a PBR plan and timing following the outcome of this Application. As well, filing of a PBR plan will need to consider the timing of any proposed amalgamation of the three Terasen Utilities, which as noted in the response to BCUC IR 1.9.1, has not been determined.

7.4 Does TGI intend on consulting with stakeholders prior to preparing and filing a multi-year PBR proposal?

Response:

TGI intends to carry on its tradition of discussing issues and topics with stakeholders, including future plans around PBR.

7.5 Does TGI have any views as to the successes/failures or strengths/weaknesses of the PBR plan that expired in 2009 – other than what it has presented in the evidence in this case? If so, please provide; if not please indicate where in the pre-filed evidence TGI has identified the failures or weaknesses of the late PBR plan.

Response:

TGI, like other stakeholders, agreed to the initial PBR settlement agreement. TGI, like other stakeholders, agreed to extend the PBR for another two years after several years of experience with it. TGI believes the PBR was fair and benefited all parties.

TGI relies on the evidence that has been filed in this Application with respect to the successes of the PBR. The terms of the PBR agreement allowed for greater alignment of interest related to customer and shareholder of TGI by:

- Achieving record high levels of customer's satisfaction (Executive Summary, page 5).
- Generally meet or exceeded the levels set out in the Service Quality Indicators (Executive Summary, page 5).
- Earnings Sharing Mechanism allowed for a 50:50 sharing on about $138 million in cost savings related to both O&M and capital expenditure (Executive Summary, page 8).
- Costs saving measures achieved during the PBR timeframe will carry forward into the future to the benefit of customers.

Given these outcomes, TGI regards the PBR as a success and thus has not identified any failures or weaknesses in the Application.

7.6 Please provide a comprehensive definition as to what components comprise TGI's "controllable costs."

Response:

Controllable costs in the context of TGI's RRA is a shorthand used to describe those costs defined not to be 'exogenous' in nature. On page 197 of the RRA, TGI outlines exogenous factors which were considered beyond the control of the Company during the PBR Period for which costs were incurred that the Company applied for and received exogenous factor treatment. These included judicial, legislative or administrative changes, orders and direction; catastrophic events, by-pass or other similar events imposed on Terasen Gas which were not reflected in the 2003 base upon which subsequent year's rates were set. Also included in exogenous factors were changes in GAAP, standards and policies and changes in revenue requirements resulting from directions from the Commission.

In Part III Section C, pages 432-437 of the Application, Terasen Gas has requested the approval of deferral accounts, such as the Tax Variance and IFRS Transitional deferral accounts, that will capture certain exogenous factors and un-controllable items in the forecast period.

TGI recognizes that costs classified as "controllable" costs, using this shorthand, are inevitably going to be driven in varying degrees by external factors such as those described in the External Situational Context chapter of the Application and are thus not purely controllable by TGI in the literal sense.

7.7 Assume the answer to 4.1 above is yes. Please explain TGI's view on the impact of deferred costs being recovered within the two year RRA period on future PBR plans.

Response:

As stated in TGI's response to BCOAPO IR 1.4.1, no work that was considered critical to the ongoing safety of operations was deferred during the PBR period. Some of the costs that were

deferred are now required to be incurred, and these costs are appropriately recovered in this RRA period. TGI continues to defer expenses that are capable of being deferred, as was the case during the PBR period, as this represents a prudent management of resources.

While TGI has expressed a desire to discuss a future PBR with stakeholders at some point, and is hopeful that the outcome of this RRA will provide the basis for further discussion, the rates for 2010 and 2011 must be set based on the revenue requirement in the RRA period and not based on speculation about what a future PBR might entail. TGI respectfully suggests that the subject matter of this question is best left for future discussions after the decision is rendered.

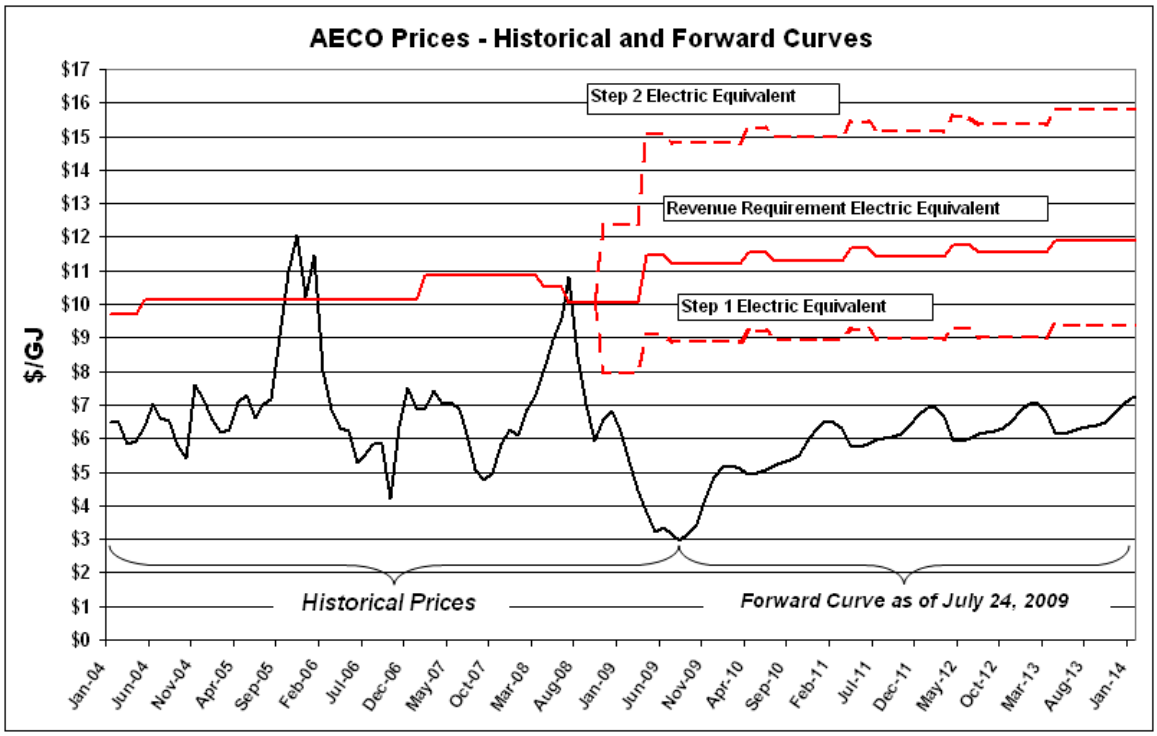
8.0 Reference: Part III, Section A, page 62, Figure A-5 and page 66, Figure A-9

8.1 Please update these figures using the most recent data available.

Response:

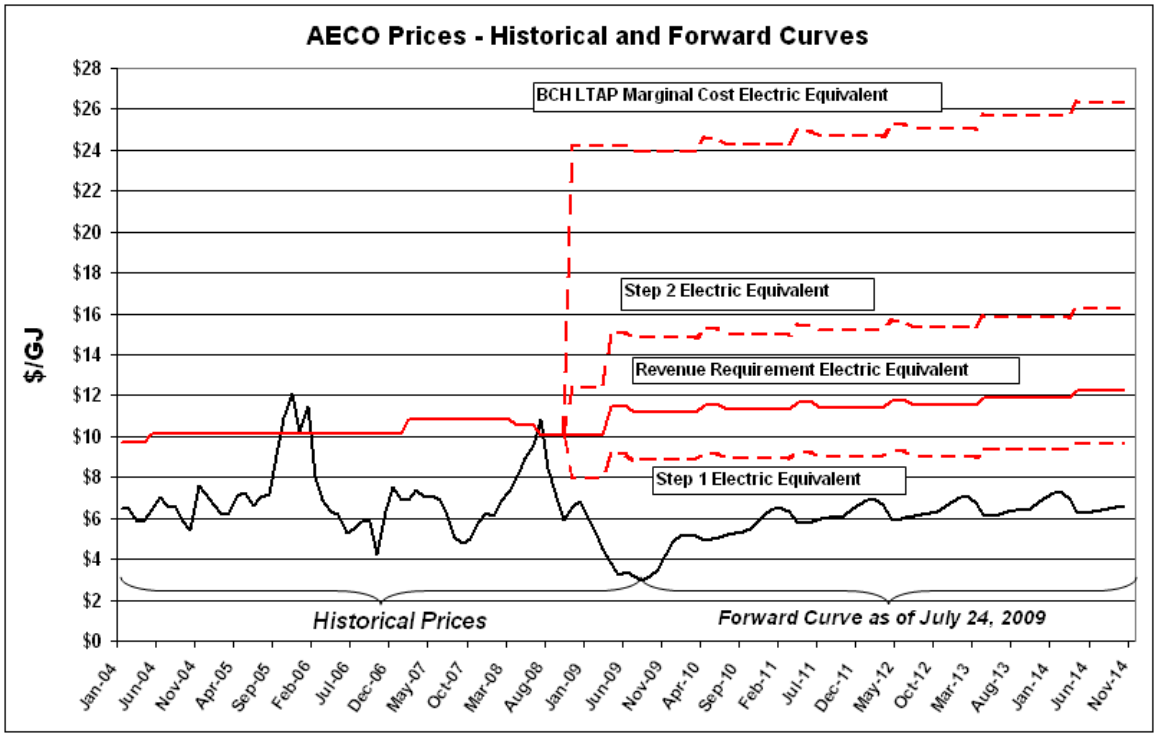
The following is Figure A-5 of Part III, Section A, page 62 updated with a more recent AECO forward price curve as of July 24, 2009.

Figure 1.8.1a: AECO Prices vs. Electric Equivalent Commodity Component using Current Prices as of July 24, 2009



The following is Figure A-9 of Part III, Section A, page 66 updated with a more recent AECO forward price curve as of July 24, 2009.

Figure 1.8.1b: AECO Prices vs. Electric Equivalent Commodity Component using Current Prices as of July 24, 2009 with BC Hydro Marginal Cost of Supply



Minor adjustments were also made to the historical electric equivalent in both graphs to correct errors related to BC Hydro rates in the graphs presented in the Application. The changes do not affect the forward price curves or electric equivalents and are immaterial changes with respect to the historical competitiveness of natural gas prices with electricity rates.

9.0 Reference: Part III, Section A, page 64, Figure A-7

9.1 Please confirm that all of the parameters in this figure are exogenous to TGI.

Response:

TGI is unclear how the term "exogenous" is being used in the question, but interpret it as being a reference to the source data being from a third party source.

The costs in Figure A-7 is provided to Terasen Gas by Habart & Associates Consulting Inc. who estimates the cost of ducting at between $2 and $3 per sq ft of house space, $1,700 a 90% AFUE furnace and $100 annually for maintenance; the costs in Figure A-7 is based on a 2,500 sq ft house.

The 18 year measurable service life of a gas furnace is from the *American Society of Heating, Refrigeration and Air-Conditioning Engineers* (*ASHRAE*) 2007 Handbook HVAC Applications Table 4 (Comparison of Service Life Estimates) section 36.3.

9.2 Please provide any information that TGI has in respect of the differences in new house prices between houses with gas space heating and houses with electric baseboards.

Response:

It is difficult to quantify the price difference between gas heated and electrically heated new homes. Typically the housing product with electric heat is at a lower price point with lower end finishing and appliances set for a different market segment. Gas heated homes are usually marketed to a different segment and include many upgrades over the electrically heated homes. Further, since developers price homes based upon many more factors than just the heating system, it is not possible to compare a home with and without a gas fired heating system. We are not aware of any examples of similar homes where the only difference is the heating system.

9.3 Please provide any information that TGI has in respect of the differences in resale house prices between houses with gas space heating and houses with electric baseboards.

Response:

It is difficult to quantify the price difference between gas heated and electrically heated resale homes. Typically the housing product with electric heat is a lower price point with lower end finishing and appliances set for a different market segment. Gas heated homes are usually marketed to a different segment and include many upgrades over the electrically heated homes. We are not aware of any examples of similar homes where the only difference is the heating system.

9.4 Please provide the most recent data with respect to relative numbers of new homes constructed or planned with electric baseboards and new homes constructed or planned with gas space heating. Please advise of any historical trends that TGI is aware of in this respect.

Response:

According to Canada Mortgage and Housing Corporation (CHMC) Prepared by BC Stats, March 2009, there were 19,591 housing starts in the Lower Mainland for 2008. CHMC does not capture heating source information.

Historical trends from Natural Resources Canada show that electric baseboard heating is growing as a percentage of the heating source in homes in British Columbia. From the period of 1990 to 2006 electric baseboard heating grew from 24% to 28.1% of the market

According to Natural Resources Canada, Office of Energy Efficiency, Residential Sector British Columbia, Table 21: Heating System Stock by Building Type and Heating System Type (the latest year for which numbers are available is 2006):

- In 1990, 24% of homes in B.C. were heated by electric baseboard.
- In 2006, 28.1% of homes in B.C. were heated by electric baseboard.
- In 1990, there were 307,000 homes heated in B.C. with electric baseboard.
- In 2006, there were 493,000 homes heated in B.C. with electric baseboard.

From 1990 to 2006, this is an increase of 61%.

- In 1990, there were 684,000 homes heated in B.C. with Natural Gas.
- In 2006, there were 973,000 homes heated in B.C. with Natural Gas.

From 1990 to 2006, this is an increase of 42%.

10.0 Reference: Part III, Section A, page 71, Table A-1, B.C. Economic Outlook

10.1 Please indicate whether TGI expects to do relatively better financially than its peers in Ontario and Alberta over the 2009-11 period due to the relatively good economic outlook for B.C.

Response:

TGI assumes that "relatively better financially", relates to the Company's earnings, which are currently driven by the ROE formula. The Terasen Utilities have filed an Application with the BCUC in May, 2009 requesting an increase to its allowed ROE, but the result of that Application is not yet known. There was a recent generic cost of capital proceeding in Alberta respecting which a decision has not yet been announced. During the 2009-11 period the distribution utilities in Ontario may seek higher returns on equity from their regulator. Since the relative financial performance of the utilities in B.C., Alberta and Ontario will be affected by regulatory decisions it is not possible to forecast how TGI will do financially compared to utilities in other provinces.

11.0 Reference: Part III, Section A, page 73, Looming Demographic Challenge

11.1 Does this challenge that TGI faces differ materially from those faced by other Canadian regulated gas distributors? Please explain.

Response:

The challenge being faced by TGI appears to be shared by many others in the Canadian gas industry, including regulated gas distributors. The Canadian Gas Association (CGA), in its Fall 2007 report entitled "Workforce Demographics: Addressing An Aging Workforce in the Natural Gas Industry", summarized the findings of a study looking at the workforce demographics within this sector as compared to other industries and similar sectors. The report states: "In general, while all Canadian industries are feeling the impact of these factors, evidence shows that natural gas utilities are being affected to a greater degree". This is discussed in further detail in Part III: Section B, Tab 2, page 211 of the Application. A full copy of the report and its findings can be found in Appendix F-6.

12.0 Reference: Part III, Section B, pp. 78-102, Management Excellence 2003-09

12.1 Please provide a brief summary list detailing the changes/improvements made between management practices, policies, and procedures during 2003-09 and those in 2002.

Response:

Please refer to TGI's response to CEC IR 1.2.2 highlighting the areas during the PBR period where management introduced initiatives to create synergies and efficiencies.

The Utilities Strategies Project (USP) had a significant impact on the structure and back office operations of the Terasen Utilities. The USP resulted in the implementation of a single management team along with common work processes and IT platforms to create a more effective and sustainable support organization across the three utilities. The operational integration of the utilities created the need for shared services in which TGI delivered common services in all major functional areas to support the operation of the two other utilities. Management practices and policies were aligned where required to support the common management approach.

The Meter to Cash refers to all activities from the reading of the customer's meter to processing of payment. Prior to 2004, TGI was challenged to manage the bad debts and write-offs associated with collection activities. Through tightening of collection practices and implementation of a sound set of internal controls over the Meter to Cash process, TGI has been able to significantly reduce its bad debt exposure.

The implementation of a Centralized Asset Management approach in Distribution Services enabled the start of the standardization of operating practices. Assets were managed centrally to optimize their planning, construction and maintenance resulting in changes in maintenance processes and practices.

Department restructuring initiated by management occurred as required to ensure the continued effective delivery of service to customers. Department processes and procedures changed as required to meet requirements.

The above highlighted changes during the PBR period demonstrates and supports the successful track record and excellence of TGI management in introducing changes in practices, policies and procedures for the benefit of customers.

12.2 Does TGI attribute any and all changes made or claimed improvements in the period 2003-09 to the existence of the PBR Plan? If so, does this mean that no improvements or initiatives would have been undertaken had TGI been under cost of service regulation and, hence, management would have been "less or not quite as excellent" during this period? Please explain, identifying which changes/improvements would not have been made under cost of service regulation.

Response:

The question is hypothetical and asks TGI to speculate on what might have been the case under a different regulatory regime over the past 7 years. As noted in the response to BCOAPO IR 1.22.1, during a multi-year PBR period, the utility is incented to manage its costs effectively in order to achieve increased returns and provide shared savings with customers. That being said, under the traditional regulatory model it remains in the overall Company's economic interest to manage costs as effectively as possible. Accordingly, although TGI cannot know for certain what might have been the case, all of the changes and improvements might have been made even without the PBR in place. What TGI does know is that, in the end, the PBR Plan accomplished what it was meant to do. The interests of customers and the Company were aligned with improvements and efficiencies realized for the benefit of both sides.

13.0 Reference: Part III, Section B, p. 100, 2009 Balanced Scorecard

13.1 Please provide a summary table showing targets and results by year for each year of the PBR Plan.

Response:

The following scorecard targets and results are for all 3 gas group companies; TGI, TGVI and TGW. A separate scorecard for just TGI is not available. The overall results during the PBR period demonstrate the success of the Terasen Utilities in delivering on a series of key performance measures, aligning its business activities and maintaining its focus on Operational Excellence for the benefit of customers and its shareholder.

Performance Measure		2004		2005		2006		2007		2008	
		Target	Results	Target	Results	Target	Results	Target	Results	Target	Results
FINANCIAL	Terasen Gas Group Net Earnings					$99.5m	$105.9m	$103.3m	$108.2m	$105.2m	$111.7m
	Gas Segment Earnings before Interest & Taxes	$262.2m	$261.9m	$271.9m	$267.4m						
	Kinder Morgan Inc. EPS					$5.00 US	$5.00US				
	Inc. Earnings per Share	$1.38	$1.40	$1.48	$0.97						
CUSTOMER	O&M per Customer	$244.00	$238.80	$235.00	$229.80	$234.00	$231.41	$231.00	$224.27	$231.31	$229.15
	Base Capital	$92.5m	$81.1m	$113.5m	$94.8m	$122.4m	$103.2m	$102.4m	$103.9m	$124.8m	$115.4m
	Customer Satisfaction	77.5%	73.9%	77.5%	77.2%	78.0%	77.9%	78.0%	79.3%	79.0%	79.7%
KEY PROCESSES	Credit & Collections	0.46%	0.41%	0.43%	0.27%	0.39%	0.32%	0.35%	0.27%	0.35%	0.24%
	Customer Additions	11,580	15,984	15,500	16,976	16,900	14,417	17,000	13,861	15,500	12,830
EMPLOYEE	Recordable Veh. Accid.	36	36	34	43	22	21	11	10	10	13
	Recordable Injuries	15	16	12	13	10	12	29	31	28	20
	Wellness	5.8	5.6	5.5	5.6	5.3	5.7	5.3	5.7	5.6	5.1
	Public Safety	<----------*Service Quailty Indicators Results* ---------->									

Please refer to response BCOAPO IR 1.13.2 for a description of how measures and weightings are determined.

13.2 Please explain the relative weights attached to each of the targets and describe how they were determined.

Response:

Measure	2004	2005	2006	2007	2008	2009
Customer	30%	30%	30%	30%	30%	30%
Financial	35%	35%	35%	25%	30%	25%
Key Processes	20%	20%	20%	20%	15%	20%
Employee	15%	15%	15%	15%	15%	25%
Total Weighting	**100%**	**100%**	**100%**	**90%**	**90%**	**100%**

The objective of the scorecard is to align the business activities to the vision and strategy of the organization. The scorecard is made up of four categories. Each category is assigned a weighting to promote behavior designed to achieve an optimum balance of meeting the expectations of customers, stakeholders and the shareholder. In general, each category was assigned roughly similar weightings recognizing the relative equal importance of each of the categories to Terasen Gas' business. As these expectations change over time, the scorecard weightings are reviewed to ensure they continue to stay in alignment.

All scorecard measures and weightings are reviewed and approved by the Executive Leadership Team and the Board of Directors.

13.3 Please describe briefly how annual targets were determined over the PBR Plan period.

Response:

Scorecard targets are set annually by the Executive Leadership team and approved by the Board of Directors. Over the PBR period, scorecard targets for the four categories of measures, Financial, Customer, Key Processes and Employee were set in a fashion that responded to evolving business needs and priorities while maintaining the focus on Operational Excellence. The targets for the measures were set by reviewing historical results, financial and economic trends, incorporating expectations of the future while ensuring continued focus on Operational Excellence and alignment of customers and shareholder interests. Where appropriate, the targets are set to drive improvement in performance over our own historical performance as well as against our peers.

The use of the balanced scorecard brings balance and transparency to Terasen Gas' business; providing focus to deliver on a series of key success measures critical to its business; aligning its business activities and maintaining its focus on Operational Excellence for the benefit of customers and its shareholder.

13.4 Please provide any information TGI may have regarding what the Balanced Scorecard would have shown in the pre-PBR Plan period.

Response:

2003 TGI Scorecard results are as follows:

Terasen Gas Inc. 2003 Scorecard
Year End 2003 Results

		Year End Results	Target
FINANCIAL	Share Earnings (EPS)	$2.56	$2.60
	Utility Earnings	$73.7	$69.8m
CUSTOMER	O&M and Capital Expenditures	$250.4m	$261.7m
	Customer Survey Score	73.9%	77.5%
	Customer Process	Target	*threshold & strategies*
	Order Fulfillment	78.7%	80%
PROCESS	Meter to Cash	0.43%	0.46%
SAFETY	Vehicle Accidents	30	36
	Lost Time Injuries	12	19
	Wellness	5.54	6.39
	Public Safety		

Well Ahead | On Track | Needs Attention | Needs Action

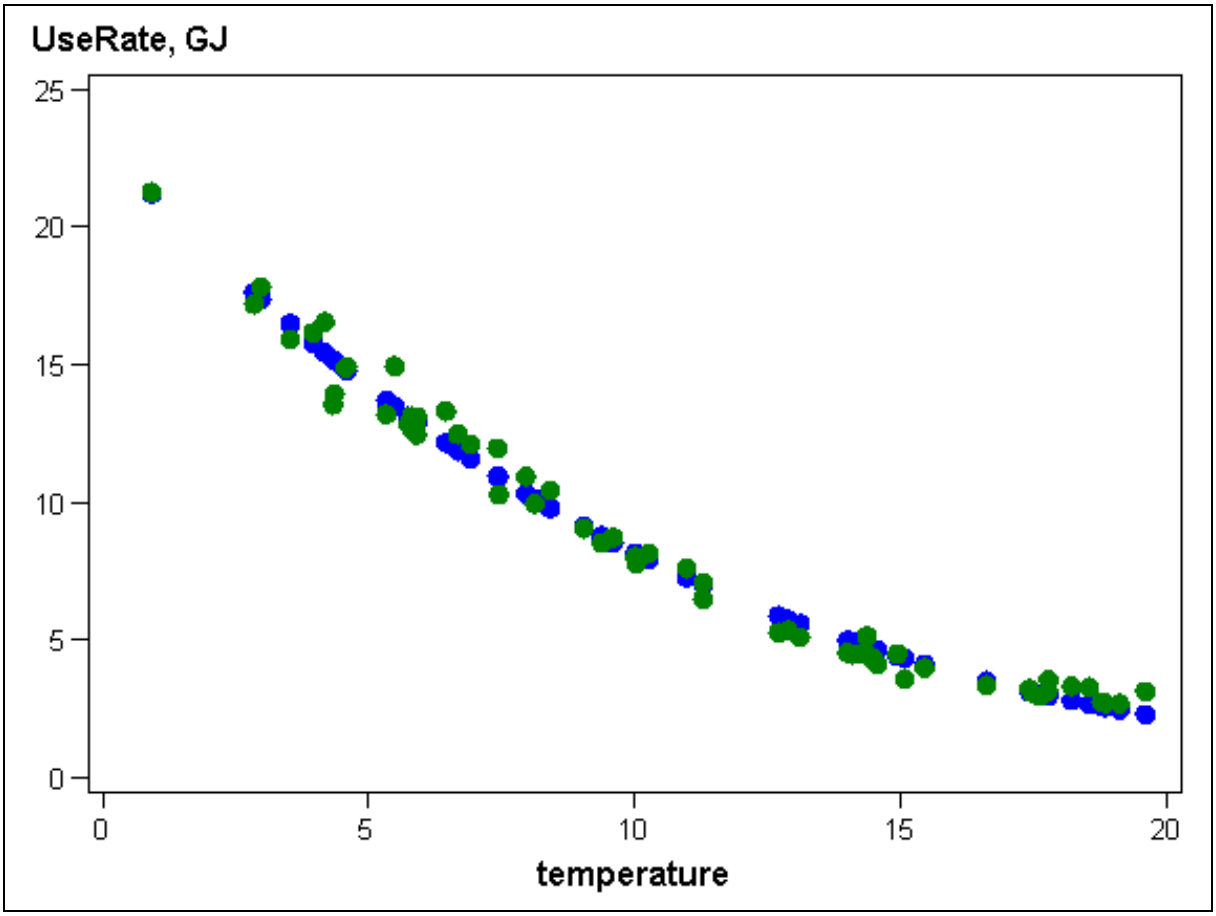
The scorecard categories and measures identified prior to the PBR period are similar to those that exist today. Consequently, Terasen Gas' pre–PBR results are consistent with those demonstrated throughout the PBR period. Terasen Gas continues to remain committed to operational excellence for the benefit of customers, stakeholders and the shareholder.

14.0 Reference: Part III, Section B, p. 110, Table B-1-3 and Appendix D-1

14.1 Please describe the normalization methodology and indicate whether any changes have been made in it since 2002. If so, please provide details.

Response:

Please see TGI's response to BCUC IR 1.52.3.



14.2 Please provide a brief description as to how the data in Appendix D-1 is combined in the data shown in Table D-1-3.

Response:

Table B-1-3 illustrated on Page 110 of the Application contains the same data that is illustrated on the last table of the Normalized Actual Demand, TGI Consolidated – All Regions, in

Appendix D-1 of the Application. The consolidated data illustrated in Appendix D-1, for customer additions and both normalized and actual volumes is a sum of the regional data. For use per customer rates, the consolidated data is a weighted average of the regional data (using volumes and customers to determine the weighted average).

15.0 Reference: Part III, Section B, pp. 115-116, Table B-1-4, SQI Performance

15.1 Please indicate whether TGI has any comparable data for the pre-PBR Plan period, and, if so, please provide it.

Response:

The following SQI data was included in the 2004 -2008 Multi Year Performance Based Rate Plan Application (Appendix C -A-1, Pages 1-13), filed in April 2003 :

	Performance Indicator	2000	2001	2002
1	Emergency Response Time (Time Dispatched to Site - Emergency - Blowing Gas)	21.2 minutes	21.7 minutes	20.5 minutes
2	Speed of Answer – Emergency (% of calls answered within 30 sec.)	90.3%	91.2%	95.9%
3	Speed of Answer – Non-Emergency (% of calls answered within 30 sec.)	72.0%	79.0%	73.8%
4	Transmission Reportable Incidents	3	2	1
5(a)	Index of Customer Bills Not Meeting Criteria	Not Available	Not Available	Not Available
5(b)	Percent of Transportation Customer Bills Accurate	Not Available	Not Available	Not Available
6	Meter Exchange Appointment Activity	Not Available	Not Available	92.2%
	Directional Indicator			
1	Leaks per Kilometer of Distribution Mains	0.0046 (170 leaks)	0.0034 (126 leaks)	0.0043 (160 leaks)
2	Number of Third Party Distribution System Incidents	1284 incidents	1132 incidents	1242 incidents

Performance indicators 7-10 of the today's set of SQIs were added at a later date.

15.2 Please indicate whether TGI expects to aim for more stringent benchmarks for any of the existing SQIs in the future.

Response:

The current SQI's were arrived at as part of the Negotiated Settlement that resulted in the TGI PBR. The SQI's were meant to address both stakeholder and Company desires and were balanced against other factors and mechanisms of the Negotiated Settlement. In future PBR's TGI would be open to including SQI's in the terms of the agreement. However, TGI is not proposing any SQI's for the RRA period.

15.3 Please confirm that, in addition to the SQI benchmarks not met as listed on page 116, for the Emergency Response Time SQI, TGI did not meet the benchmark in 2003, 2004, 2005, and 2006 (and for 2003-2008 average).

Response:

TGI did not meet the Emergency Response Time of 21.1 minutes from 2003 to 2006. For the period 2003-2008, TGI marginally missed the target by an average of 15 seconds. This information was shared with stakeholders during each Annual Review.

From 2006 to present we changed our processes in dispatching staff to emergencies resulting in a 1 minute improvement in 2007 & 2008. We will continue to examine areas for improvement in future.

15.4 Please explain why for 2009 YTD April actual, TGI was not meeting benchmarks for Emergency Response Time, Index of Customer Bills Not Meeting Criteria, Percent of Transportation Bills Accurate, and Meter Exchange Appointment Activity.

Response:

Emergency Response Time: This SQI measures average response time to emergencies identified as a hit line with blowing gas and includes incidents both during and after working hours including weekends. The geographical area covered by the metric is Lower Mainland and Interior.

There are several factors which are putting upward pressure on the year-to-date SQI emergency response time results.

- In January 2009, the Lower Mainland and parts of the Interior experienced a once in forty year weather event with significant snowfalls which limited TGI's ability to routinely navigate urban streets and added approximately one minute to the January average compared to a year earlier.
- We are also seeing an increase in the amount of time field employees require to interrupt their core work to respond to emergencies. Depending on the type of job, this unscheduled interruption requires some additional time to make their existing work site safe before proceeding to attend the emergency.

- In April/May 2009, TGW commenced the Whistler conversion project (conversion of Whistler propane customers to natural gas) which required relocation of skilled resources from the existing TGI field work force. As a result of temporarily re-deploying some of the existing TGI field work to Whistler, the pool of available first responders in some of the larger TGI service areas has been decreased.

- Lastly, the mix of emergency incidents (i.e. large centre vs. remote areas) has recently changed with decreases in the larger cities whereas in remote areas it has remained constant. The response times for remote locations are historically higher than the larger centre due to staffing and geographical distances travelled. The weighting of remote town events has increased and the higher response times recorded in these locations has pushed the overall response time upward.

We continue to examine opportunities to improve emergency response now and in the future particularly as changing external and internal events impact our performance.

Index of Customer Bills Not Meeting Criteria

This metric is a composite measure that combines billing accuracy, timeliness and completion. Results for 2009 YTD in April were driven by billing accuracy issues resulting primarily from a late payment charge calculation error. The error began when the CIS system outsourced to CustomerWorks LP received a technical upgrade in late 2008. It was identified in January 2009 and the system correction was implemented in February 2009. A secondary impact identified in March 2009 was an error related to charging PST and the ICE Levy to certain exempt customers. This was corrected in March.

Percent of Transportation Bills Accurate

This metric was also impacted in early 2009 by the late payment charge calculation error noted above.

Meter Exchange Appointment Activity:

This SQI measures the percentage of meter exchange appointments met.

TGI only recently detected an error in the reporting used to provide the data for this SQI. The restated numbers for 2009 are as follows:

Field Completed Month	Percent Appts Kept
Overall Result	95.1%
Jan-09	93.2%
Feb-09	96.3%
Mar-09	95.9%
Apr-09	95.1%
May-09	95.9%
Jun-09	95.5%
Jul-09	94.7%

15.5 Please update the column "2009 YTD Actual."

Response:

	Performance Indicator	June 2009 YTD Actual
1	**Emergency Response Time** - Time Dispatched to Site - Emergency - Blowing Gas	23:00 minutes
2	**Speed of Answer – Emergency** (% of calls answered within 30 sec.)	98.3%
3	**Speed of Answer – Non-Emergency** (% of calls answered within 30 sec.)	76.7%
4	**Transmission Reportable Incidents**	0
5(a)	**Index of Customer Bills Not Meeting Criteria**	5.23
5(b)	**Percent of Transportation Customer Bills Accurate**	92.3%
6*	**Meter Exchange Appointment Activity**	95.4%
7	**Accuracy of Transportation Meter Measurement First Report**	98.9%
8	**Independent Customer Satisfaction Survey**	80.0%
9	**Number of Customer Complaints to BCUC**	32
10	**Number of Prior Period Adjustments**	14

	Directional Indicators	
1	Leaks per Kilometer of Distribution Mains	0.001426
2	Number of Third Party Distribution System Incidents	609

*Note:

Due to improved reporting, Measure 6 has been adjusted to exclude those appointments not met as a result of the customer not being home for their scheduled appointment.

15.6 The evidence states that "[d]uring 2008 and Q1 2009, Terasen Gas has experienced declining performance in key SQI measures that are delivered by Accenture Utilities BPO Services ("AUSBOS") under contract with CWLP." Please identify the key SQI measures referred to, what, if any penalties AUSBOS has suffered as a result of this declining performance, specify exactly how TGI has responded to this challenge, and identify any incremental costs incurred by TGI as a result of this declining performance.

Response:

The specific SQI measures referenced in Part III, Section B, pp. 115-116, Table B-1-4 are as follows:

2008

SQI 3: Speed of Answer – Non-Emergency

SQI 5(a): Index of Customer Bills Not Meeting Criteria

SQI 5(b): Percent of Transportation Customer Bills Accurate

YTD April 2009

SQI 5(a): Index of Customer Bills Not Meeting Criteria

SQI 5(b): Percent of Transportation Customer Bills Accurate

With respect to penalties assessed under the contract as a result of these performance issues, please refer to the responses to BCUC IR 1.93.2.

In responding to these issues, TGI has worked directly with AUBPOS to ensure the root cause of issues leading to missed metrics was understood in each instance and corrective action implemented by AUBPOS. No incremental costs have been incurred by TGI as a result of these issues.

15.7 Please describe what changes, if any TGI anticipates to the SQI measures, targets or other metrics, assuming the Customer Care Enhancement Project CPCN is approved as filed.

Response:

As noted in response to BCOAPO IR 1.15.2, TGI is not proposing any SQI's for the period of the RRA.

TGI respectfully submits that discussion of changes to metrics resulting from the Customer Care Enhancement Project CPCN is more relevant to the CPCN Application and is more efficiently addressed within the proceeding related to that application, or a future PBR Settlement. The Project is not scheduled to "go live" until 2012, and there are no revenue requirement impacts on this Application.

16.0 Reference: Part III, Section B, pp. 116-117, and p. 141, Commodity Unbundling

16.1 Please provide historically and by rate class the number of customers who had signed with a marketer for each year 2004-08.

Response:

The table below shows the number of customers who have signed a gas marketer contract each year by rate class since the start of the Commodity Unbundling Program in 2004. Enrollment for Commercial Commodity Unbundling started in May 2004 with gas flows beginning in November 2004. Residential Commodity Unbundling enrolments started in May 2007. Gas flowed for these contracts starting in November, 2007. Unbundling is only available to Rate Schedules 1, 2, and 3 customers of TGI.

These numbers represent the gross enrollments and account for the number of transactional enrollment activity submitted to the Gateway for Energy Marketers ("GEM") portal. These gross enrollment counts may include customers renewing contracts after the expiry of previous contracts, especially where they had a shorter initial term. The gross enrollments also do not take into account the number of contract drops and cancellations from the program. Customer contracts may drop or cancel for various reasons including but not limited to 10 day cancellation period drops, account finalization drops, dispute resolution drops and contract expiry drops.

Customer Choice Commodity Unbundling Program – Gross Enrollments			
	Residential Customers Rate 1	Commercial Customers Rate 2 & 3	Total
2004	-	1,412	1,412
2005	-	10,703	10,703
2006	-	5,522	5,522
2007	177,735	3,857	181,592
2008	101,875	5,288	107,163
Total	279,610	26,782	306,392

16.2 Please indicate whether TGI has any data with respect to customer complaints regarding marketers' behaviours and practices. If so, please provide.

Response:

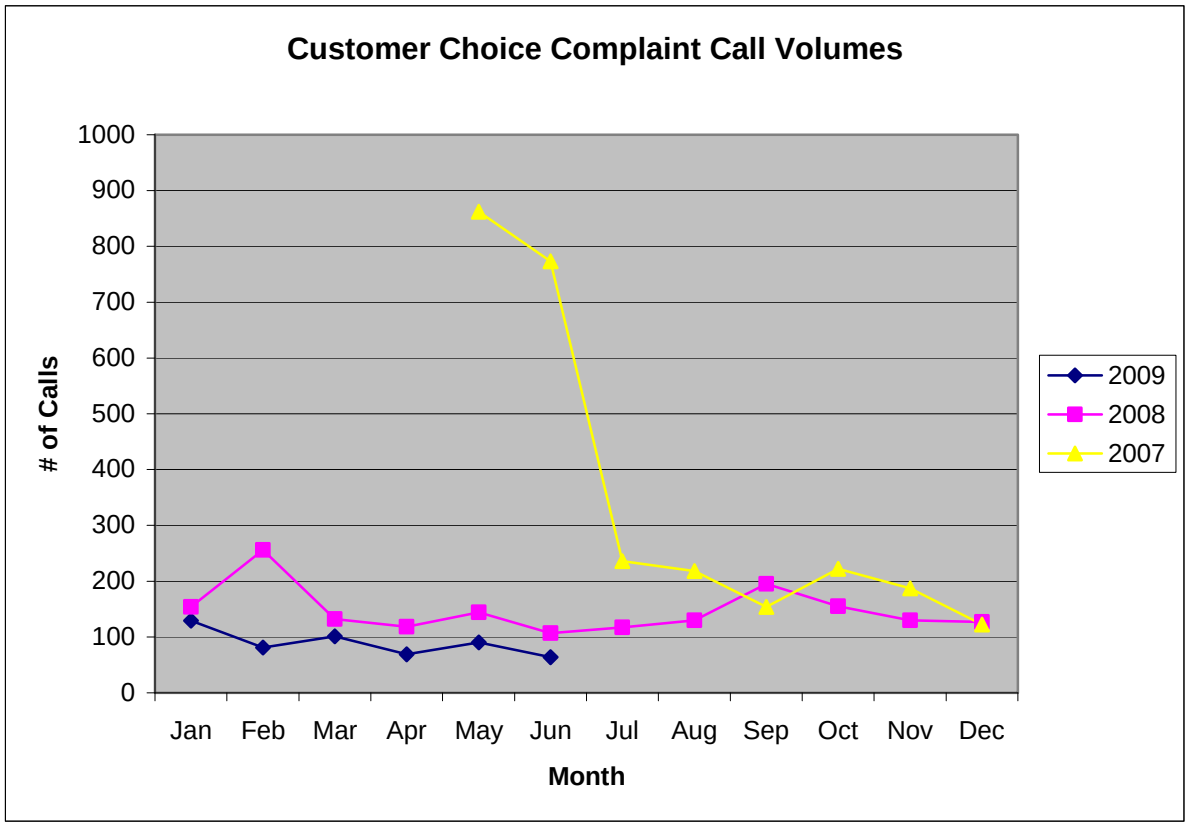
TGI tracks all customer calls through its Call Centre. Calls from customers participating in the Customer Choice program, including where customers have been contacted by a gas marketer, are tracked using several reason codes and include a general Commodity Unbundling complaint code. An additional level of detail, such as customer complaints by rate class (Rate 1, 2, 3) or type of gas marketer behavior and practice are not tracked. Customer complaints relating to the Customer Choice program most often focus on gas marketer sales practices. Complaints statistics do not include disputes initiated by a customer. Disputes are logged and managed separately.

Prior to the start of Residential customer enrollments in May 2007, Commodity Unbundling customer complaints were not tracked separately but rather included as part of all Terasen Gas customer complaints.

At the beginning of customer enrollments in the Residential Commodity Unbundling program in May 2007, more than 860 complaints were logged. Since that time, the number of complaint calls has declined steadily, with 64 logged in June 2009.

Figure 1: Customer Choice Related Complaints by Month

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2009	129	81	101	69	90	64							**534**
2008	154	256	132	118	144	107	117	130	195	155	130	127	**1765**
2007					862	773	236	218	154	222	187	122	**2774**



16.3 TGI states the cost of the Commodity Unbundling Program to be $17M. Please confirm that this is an upfront cost rather than a total cost including operating costs and please provide annual operating costs associated with this initiative.

Response:

The cost of implementing the Commodity Unbundling program was $17 million. This cost included the combined upfront cost for the implementation of the Commercial and Residential Unbundling Program through the end of 2007. The Commercial Commodity Unbundling Program was implemented in 2003 and 2004, followed by the Residential Commodity Unbundling program in 2006 and 2007. These implementation costs include system development and Customer Education costs but do not include program enhancement costs incurred after 2007. Annual operating and maintenance costs of the program are also not included in the $17 million.

The following table shows annual operating and maintenance costs for the Commodity Unbundling Program from 2004 to June 30, 2009.

Commodity Unbundling Program Operating Costs 2004 - YTD 2009

	2004	*2005*	*2006*	*2007*	*2008*	*YTD June 30 2009*
Operating and Maintenance Costs (Before Tax)	$59,127	$399,275	$231,540	$679,571	$7,326,812	$639,657
Marketer Transaction Fee Recoveries (Before Tax)	($1,577)	($66,317)	($121,021)	($399,682)	($3,502,013)	($641,875)
Balance to Deferral Account (Before Tax)	$57,550	$332,958	$110,519	$279,889	$3,824,799	($2,218)

The significant cost increase noted in the 2008 and 2009 Operating and Maintenance costs included the following:

- The Commission approved Customer Education costs of $2,987,404 in 2008 and $ 97,730 in 2009 (year-to-date of the approved $500,000). Prior to 2008, Customer Education costs were identified as program implementation costs.
- A $781,000 Customer Information System upgrade to address marketer and Commission performance requirements.
- Higher than typical Backstopping Service charges.

Operating and maintenance costs are offset by administration fees paid by gas marketers for participating in the program. These fees are intended to ensure that gas marketers pay for an increasing portion of the cost to operate and maintain the program. The higher Backstopping Service charges incurred in 2008 resulted in higher levels of Marketer Recovery fees, included the following:

- Backstopping Service charges of $ 1,719,435.07 were recovered from CEG Energy Options, Wholesale Energy Group and several other gas marketers. Starting in January 2008, Terasen has been required to provide backstopping services to a number of gas marketers due to shortfalls in required deliveries.

Through the end of 2009, any operating costs not offset by fees paid by gas marketers are accumulated in a deferral account and recovered from customers eligible to participate in the program (Rate Schedule 1, 1U, 2, 2U, 3, and 3U customers within the Lower Mainland, Inland, and Columbia service areas, excluding Revelstoke and Fort Nelson).

16.4 Given that at March 2009, only 17% of eligible customers were participating in this program, why does TGI feel that the costs borne mainly by the non-participating 83% are justified?

Response:

Terasen Gas continues to believe that the Commission's decision that the cost of the Commodity Unbundling program should be borne by all eligible customers is reasonable.

The Commercial and Residential Unbundling program was implemented in response to the objectives set out in the 2002 BC Energy Policy. This policy called for providing small volume customers with choice relating to the natural gas commodity. In order to facilitate this option, the Commission in Letter No. L-25-03 dated June 6, 2003 stated "*The implementation and maintenance costs will be recovered from customers in those rate classes that are eligible for the service. Annual operating costs (fixed and transactional costs) should be recovered, to the extent possible, from marketers.*"

Recovering the implementation and ongoing operating costs from all eligible customers was necessary in order to establish this unbundling program. This program provides all customers with the option to choose where they buy their natural gas commodity from at a time convenient and advantageous to them. Customers who do not currently participate in the program because they do not have an active contract with a gas marketer may choose to participate in the future. The ability to select a fixed rate contract at any time represents a benefit to all eligible customers. People's situations change, as do energy prices. So a consumer's gas supply choice today is not necessarily indicative of their future choice.

All eligible customers receive a benefit from having the ability to exercise the choice of whom they choose to purchase their natural gas commodity from, regardless of whether they immediately choose to change their supplier.

17.1 Reference: Part III, Section B, p. 142, Summary of Operational Performance

The evidence states that "Terasen Gas has a solid history of code compliance and has implemented management systems and/or operating practices to ensure compliance ... As part of its efforts, Terasen Gas continues to be proactive in looking for improved ways to provide safe, reliable, cost-effective and environmentally responsible service. For operating emissions management, Terasen Gas has a long standing history of being proactive in this area."

17.1 Please indicate whether this describes Terasen's historical record from the start or starting with the PBR Plan.

Response:

Terasen Gas' history of environmental management and emissions management pre-dates the start of the PBR Plan in 2003. Terasen Gas (then BC Gas Inc.) formed its first Environmental Committee in 1990 to develop an environmental strategy and provide corporate leadership to manage environmental risks. The first External ISO 14001 Environmental Management System Assessment was conducted by KPMG in 1998. Terasen Gas' emissions management program began in 1995, including the first submission to the *Voluntary Challenge & Registry* (VCR) Program that reported on greenhouse gas emissions and reduction efforts. Terasen Gas has systematically measured greenhouse gas emissions from our operations since that time, having maintained average annual emissions below 1990 levels since 2000, up to and including 2008.

18.0 Reference: Part III, Section B, p. 146, Employee Safety

Regarding employee safety, the evidence states that "Terasen Gas continues to meet and exceed these challenges and remain comparable to peer CGA companies."

18.1 For the period 2003-08, please provide data on Terasen Gas and peer CGA companies to support this statement.

Response:

When it comes to employee safety, TGI compares itself to other CGA local distribution companies. The CGA receives safety accident statistics from member companies on a quarterly basis and publishes the results so each reporting company can assess their performance relative to other CGA companies. The two general areas of safety reporting are "employee safety" and "vehicle accidents". Terasen Gas compares its performance against other natural gas utilities within the CGA.

Terasen Gas' safety performance continues to compare well with other CGA companies. With respect to employee safety frequency[3], the CGA annual average between 2003 and 2008 was 1.17 and Terasen Gas' was 1.36. Regarding vehicle accident frequency[4], the CGA annual average between 2003 and 2008 was 3.91, and Terasen Gas' was 3.98.

[3] Employee safety frequency is calculated by multiplying the number of injuries (lost time plus medical treatment) by 200,000, then dividing by the number of hours worked.

[4] Vehicle accident frequency is calculated by multiplying the number of vehicle accidents by 1,000,000, then dividing by the number of kilometres driven.

19.0 Reference: Part III, Section B, p. 147 and Table B-1-7, FTE Employees

19.1 Regarding the upward trend in FTEs beginning in 2007, please provide a breakdown of the increases in 2008 between demographic risks and changing business environment.

Response:

Table B-1-7 shows an overall increase of 40 FTE between 2007 and 2008 which can be broken down as follows (the overall total below adds up to 41, but this is offset by the reduction of 1 FTE from 2007-2008 in Gas Supply & Transmission):

Demographic Risk: 24 FTE

- 22 of these positions appeared in Distribution in direct response to the demographic challenges being realized in the IBEW field workforce and the lifting of the hiring freeze (see Part III, Section B, Tab 1, page 149). The 22 FTE additions were composed of a mix of Distribution Apprentices, Distribution Mechanics, and Customer Service Technicians that were hired to replace retiring employees.

- 1 Leadership Development Specialist was added to Human Resources & Operations Governance. The Leadership Development Specialist is responsible for implementing strategies, processes, programs and resources to build leadership capacity across the organization. Terasen Gas has placed renewed emphasis on Leadership Development which is a key component of our strategy to manage one aspect of the demographic challenge (see Part III, Section C, Tab 6, pp 396-397).

- 1 Pension Coordinator was added to Human Resources in response to risks identified through the succession planning process.

Changing Business Environment: 12 FTE

- 11 FTE were added to Business & IT Services in 2008 due to the changing business environment at the time. 5 net new FTE were added in Location Records in order to maintain our BC OneCall ticket turnaround time and to try to stabilize workforce turnover. The remaining 6 additions reflect net vacancies that were filled across the various groups of B&ITS. For example, we filled two vacancies in response to pressures in IT that were offset by two new vacancies in Facilities for a net change of zero between those two groups.

- 1 Regulatory Affairs Manager was added in response to increased workload resulting from changes to provincial energy policy and related regulatory proceedings.

Normal Turnover & Vacancy Replacement 5 FTE

- A total of 4 FTE were realized in Finance and Regulatory Affairs. 2 Cost of Service Managers were hired to fill vacant positions in Regulatory Affairs. Another 2 were hired in Finance to fill vacant positions for a Director of Finance and an Accounts Payable Clerk.
- The equivalent of 1 FTE was realized in Human Resources & Operations Governance. This resulted from the filling of 2 vacancies, each for a portion of the year: 1 Health & Safety Advisor and 1 Operations Compliance Auditor.

19.2 Please indicate when Terasen Gas became aware of the demographic risks it faces.

Response:

Terasen Gas has been aware of the demographic risks for quite some time and has been actively implementing a variety of plans and strategies for many years in anticipation of pending changes to its workforce and to mitigate the retirement risk. Some of these are described in detail in Part III, Section B, Tab 1, pp 147-151. In addition, workforce plans and succession plans are reviewed and updated annually through a well established set of Human Resource practices and processes that allow us to identify and address gaps in the talent pool. It is a collaborative, strategic process that is conducted across the organization to ensure we have the necessary talent available in critical areas at the appropriate time. The combination of workforce planning and succession planning ensures the Company has plans in place to develop and retain the skills, knowledge and leadership capacity to meet both customer and shareholder expectations. Our demonstrated ability to manage the demographic changes that have already affected the field workforce in Distribution is testimony to the effectiveness of this process.

19.3 Please indicate why Terasen Gas waited until 2007-08 to start to address the demographic risks.

Response:

Terasen Gas did not wait until 2007-2008 to start to address the demographic risks. The Company has been actively developing workforce plans and strategies for many years. Critical areas are identified and plans are put in place as part of the annual succession planning process. Please see response to BCOAPO IR 1.19.2.

20.0 Reference: Part III, Section B, p. 152, Table B-1-8, Turnover Rates

20.1 Please provide a breakdown of the rows labelled # Voluntary Terminations and # Involuntary Terminations, by department for each year2002-08.

Response:

Turnover Rates (FTR Employees) 2002 to 2008

	2002		2003		2004		2005		2006		2007		2008	
	Voluntary	Involuntary	Voluntary	Involuntary	Voluntary	Involuntary	Voluntary	Involuntary	Voluntary	Involuntary	Voluntary	Involuntary	Voluntary	Involuntary
Distribution	5	8	4	21	26	3	10	6	8	14	9	1	11	4
Finance & Regulatory Affairs	2	1	2	2	4	13	4	1	6	0	6	0	3	0
Business & IT Services	11	5	5	13	13	7	4	2	13	2	10	1	4	0
Human Resources & Operations Governance	2	0	0	0	5	4	1	3	3	2	2	2	1	0
Marketing & Business Development	3	1	2	5	12	1	6	2	7	9	11	0	6	5
Gas Supply & Transmission	3	0	1	7	20	5	1	0	4	0	2	0	2	0
Corporate	0	1	0	2	1	0	0	0	0	0	0	0	0	0
Other (Terasen group of companies)			5	1	2	2	5	9	5	6	2	1		1
TOTAL	**26**	**16**	**19**	**51**	**83**	**35**	**31**	**23**	**46**	**33**	**42**	**5**	**27**	**10**
(Balance)	**42**		**70**		**118**		**54**		**79**		**47**		**37**	

Note: the turnover rates in the table above include all FTR employees within the Terasen Group of Companies

20.2 Please indicate whether involuntary terminations were mainly "for cause," i.e., related to attendance or sick leave behaviours, or other.

Response:

In 2008, there were 10 involuntary terminations. Five employees were let go during probationary periods for reasons relating to suitability and/or inability to meet performance expectations. Two additional employees were terminated with pay in lieu of notice for reasons relating to suitability, and the remaining three involuntary terminations occurred when it was determined that work being performed by positions on Vancouver Island was more appropriately being performed by other positions located at Surrey Operations. No employees were terminated for cause.

In 2007, there were five involuntary terminations, one of which was for cause. Three employees were terminated with pay in lieu of notice for reasons relating to suitability, and the remaining involuntary termination was a consequence of the 2005 acquisition of Terasen Inc. by Kinder Morgan Inc. (the position was identified for elimination in 2005, but the termination did not take place until the employee's return from long-term leave in 2007).

In 2006, there were 32 involuntary terminations. Two employees did not complete their probationary periods for reasons relating to suitability and/or inability to meet performance expectations. Two additional employees were terminated with pay in lieu of notice for reasons relating to suitability. The majority of remaining employees were terminated when positions were eliminated as a result of the acquisition of Terasen Inc. by Kinder Morgan Inc., as well as the result of continuing integration of Centra Gas with Terasen Gas. No employees were terminated for cause.

In 2005, there were 20 involuntary terminations, the majority of which were as a consequence of the acquisition of Terasen Inc. by Kinder Morgan Inc. One employee was terminated with pay in lieu of notice for reasons relating to suitability, and five employees were terminated involuntarily when their positions were eliminated and they were not recalled from layoff. No employees were terminated for cause.

In 2004, there were 34 involuntary terminations. Terasen Gas did not terminate any employees for cause. The majority of involuntary terminations were as a consequence of the acquisition of Centra Gas by Terasen Gas.

In 2003, there were 53 involuntary terminations. Five employees were terminated for cause. The majority of remaining involuntary terminations occurred when positions were eliminated due to restructuring (i.e. outsourcing of meter reading to CustomerWorks), as well as the acquisition of Centra Gas by Terasen Gas.

In 2002, there were 22 involuntary terminations. One employee was terminated for cause. The majority of involuntary terminations were as a consequence of organizational restructuring (i.e. outsourcing of customer support to CustomerWorks).

21.0 Reference: Part III, Section B, p. 156, M&E Employees

21.1 Please explain (i) the choice of a defined benefit pension plan as opposed to a defined contribution plan and (ii) details regarding the other benefits changes made in 2007.

Response:

Short Term Disability eligibility for 100% salary for 26 weeks was changed to require 10 years service, a change from the previous 5 year requirement.

Employee Savings plan was introduced. The Company will contribute an amount equal to 3% of the employee's basic monthly salary.

Part time regular employees' changes to eligibility were introduced. Previously part time regular employees received the same benefits as full time regular. With the change, employees must work a minimum of 18.75 hours per week in order to be eligible for a reduced level of flex credits, as well as savings plan and employee stock purchase plan. Part Time Regular employees are no longer eligible for post retirement benefits.

For all employee groups:

Employee Share Purchase Plan (ESPP)

Fortis provided Terasen Gas employees the opportunity to purchase Fortis Shares through the Employee Share Purchase Plan which rolled out September 1, 2007. The purchase of shares is open to all groups of employees who meet the eligibility criteria. Employees are eligible to purchase up to a maximum of 10% of their annual salary per calendar year; purchases can be made by way of interest free loan or payment. The price to the participant under the plan is 90% of the average market price.

22.0 Reference: Part III, Section B, p. 160, Table B-1-12 and Appendix F, Tab 1, O&M

22.1 Please provide the actual and approved – per Decision – nominal gross O&M spending for 2003 and 2002.

Response:

($ Millions)

	2002*	2003
Approved Gross O&M	n/a	181.7
Actual Gross O&M	169.5	173.5
Difference		8.2

** This amount excludes any expenditures related to TPIP; TPIP included in 2003 is $5.5 million*

The 2002 Revenue Requirement Application was withdrawn; as a result, approved 2002 Gross O&M is not available.

22.2 Does TGI agree that a utility entering a multi-year PBR Plan has a financial incentive to not make O&M cost reductions prior to setting the PBR base?

Response:

It is difficult to generalize in the manner suggested in the question. There are many types and variations of PBR and various intended outcomes of the different types of PBR. Utilities going into a multi-year PBR may also be coming out of a variety of ratemaking models, including traditional cost of service regulation or a previous PBR plan. TGI expects that in some cases a utility going into a multi-year PBR may not be inclined to make O&M cost reductions prior to setting the PBR base. This is a reason that the base year O&M allowance going into a multi-year PBR is frequently determined from (or derived from) the results of a recent public hearing and Commission decision. The fact that the utility's O&M and other components of revenue requirements have been set through a recent public hearing process means that intervenors have had the opportunity to test the evidence and the Commission has issued its decision based on the merits of the evidence so setting the base from that starting point is generally considered reasonable and appropriate. This is the case with TGI and the 2003 Commission hearing process and decision.

It is also true that during a multi-year PBR period the utility is incented to manage its costs effectively in order to achieve increased returns. A PBR such as the one TGI is emerging from provided such incentives, while sharing savings with customers. Because these costs are the basis for or starting point from which this revenue requirement filing is being made and any new costs are explained, customers, the Commission and other stakeholders can take comfort that they are reasonable and not overstated since it has been in the Company's economic interest to manage costs as effectively as possible during the PBR period.

22.3 Does TGI agree that a utility moving towards the end of a multi-year PBR Plan has a financial incentive to make less O&M cost reductions than it would have made earlier in the PBR plan?

Response:

Please see response to BCOAPO IR 1.22.2. TGI does not agree with the general statement that a utility moving towards the end of a multi-year PBR Plan has a financial incentive to make less O&M cost reductions than it would have made earlier in the PBR plan. In the case of TGI's current PBR Plan there is a financial disincentive to allow O&M reductions achieved earlier in the PBR to be eroded, particularly given the fact that current 2010-2011 RRA is based on traditional cost of service regulation that is likely to be adjudicated through a public oral hearing process.

For TGI itself the O&M levels achieved in the last few years of the PBR term do not support the assertion in the question. As demonstrated in the tables provided on page 162 of the Application, although O&M is increasing on a nominal dollar basis at the end of the PBR period, the appropriate comparison is to look at O&M on an inflation adjusted basis, and also on a per customer basis. When comparing both of those metrics, it is evident that O&M has in fact remained consistent throughout the PBR period on a total inflation-adjusted basis, and has actually decreased on a per customer inflation-adjusted basis.

TGI does acknowledge that there may a diminished incentive to undertake new incremental O&M efficiency initiatives later in a PBR term. This is not the same thing at all as asserting that the utility has an incentive later in a PBR term to allow previously achieved efficiencies to be eroded. New incremental efficiency initiatives will generally have an associated cost for which payback and a reasonable return on investment cannot be achieved if the initiative is started late in the PBR term. However, various ways can be devised to maintain the incentive to pursue efficiencies and to overcome end-of-term issues, such as allowing the utility to retain a portion of the later-term efficiencies achieved for a period of time (like the capital benefit phase-out mechanism in the current PBR).

22.4 Please reconcile the data in Appendix F, Tab 1, with the data in Table B-1-12.

Response:

The two schedules show the same gross O&M expenses for all years except 2004. A reconciliation schedule for 2004 is shown below:

(millions)	2004	
Gross O&M	181.3	Part III, Section B, p. 160, Table B-1-12
Less: Restructuring Costs	-9.6	
Gross O&M (Adjusted)	171.7	Appendix F, Tab 1

The reconciling item is $9.6m of restructuring costs.

23.0 Reference: Part III, Section B, p. 163, Figure B-1-14, O&M per customer

23.1 Please provide the source data underlying this Table.

Response:

The table below contains the source data by utility that underlies Figure B-1-14, with the names of the utilities not specifically listed. Even though the information is publicly available, TGI recognizes potential sensitivities of the other utilities regarding the comparison of information.

OM&A per customer ($/cust)

	2003	2004	2005	2006	2007	2008
Company A	185	196	187	199	199	199
Company B	236	243	242	237	244	245
Company C	266	248	255	252	265	278
Company D	743	761	762	780	775	775
Company E	333	336	354	355	360	381
Company F	215	210	218	208	207	217
Company G	471	480	441	436	464	474
TGI + TGVI	196	197	193	195	191	196

23.2 Please discuss the extent to which the fact that comparator utilities may have different capitalization policies, impacts the relevance of this comparison.

Response:

TGI recognizes the differences in overhead capitalization policies may affect the comparability of the O&M per customer metric. To compensate for imperfect comparability between individual companies for such differences, TGI believes it is then reasonable to compare TGI/TGVI's metric to peer group highs, lows and averages. From this perspective, TGI/TGVI's net O&M per customer is significantly below the peer group average and amongst the lowest for the peer group. In fact, if TGI/TGVI collectively were to adjust its overhead capitalization retrospectively from its existing 16% to 10%, it would still rank favourable against its peers on the net O&M per customer metric.

24.0 Reference: Part III, Section B, p. 164, Table B-1-15, O&M

24.1 Please recast the data in this Table showing the historical O&M expenses by department on a per FTE basis.

Response:

Historical O&M Expenses per FTE by Department

Department	Decision 2003 [1]	Actual 2004 [2]	2005	2006	2007 [3]	2008	Projection 2009
Distribution	$ 62.2	$ 63.0	$ 67.3	$ 67.8	$ 69.4	$ 73.5	$ 67.8
Gas Supply And Transmission	179.3	158.2	170.2	172.0	168.4	183.8	188.3
Marketing & Business Development	700.0	892.2	902.7	815.0	762.0	787.2	594.3
Business and IT Services	114.0	107.0	109.7	114.9	117.7	114.8	109.5
Human Resources and Operations Governance	87.9	64.6	64.9	74.6	83.3	83.5	111.1
Finance and Regulatory Affairs	149.7	112.4	120.1	119.3	133.8	138.0	141.0
President & CEO	495.6	8,920.6	9,077.5	11,267.3	8,492.1	8,961.7	8,742.8
Total Gross Nominal O&M Expenses per FTE	**$ 152.8**	**$ 166.5**	**$ 156.4**	**$ 168.7**	**$ 164.7**	**$ 164.8**	**$ 156.1**
Distribution	$ 70.1	$ 69.7	$ 73.1	$ 72.0	$ 72.3	$ 75.1	$ 67.8
Gas Supply And Transmission	201.9	175.2	184.8	182.7	175.4	187.7	188.3
Marketing & Business Development	788.3	988.0	980.0	865.8	793.6	803.7	594.3
Business and IT Services	128.4	118.5	119.1	122.1	122.6	117.2	109.5
Human Resources and Operations Governance	99.0	71.5	70.4	79.3	86.7	85.3	111.1
Finance and Regulatory Affairs	168.6	124.5	130.4	126.7	139.3	140.9	141.0
President & CEO	558.1	9,878.0	9,854.7	11,968.7	8,843.9	9,149.9	8,742.8
Total Gross Real O&M Expenses per FTE	**$ 172.1**	**$ 184.3**	**$ 169.8**	**$ 179.2**	**$ 171.5**	**$ 168.3**	**$ 156.1**

Notes:
All amounts are in $ thousands
Gross O&M expenses are before removal of capitalized overheads and vehicle lease expenses.
Real O&M expenses have been adjusted for the effects of CPI inflation, as filed in the Terasen Gas Annual Reviews during the PBR period.
[1] *2003 Decision O&M of $181.7 million has been adjusted fto include $5.5 million of TPIP*
[2] *2004 Gross O&M of $181.3 million includes $9.6 million of restructuring costs in the President & CEO department*
[3] *Terasen Gas Squamish was amalgamated with Terasen Gas January 1, 2007. Terasen Gas Squamish O&M is therefore not included for the years 2003-2006.*

25.0 Reference: Part III, Section B, p. 169, Table B-1-15, Aging Transmission System

25.1 Please provide a Table indicating annual expenditures on

(i) transmission replacement activity;

(ii) transmission system inspection;

(iii) transmission system reinforcement; and

(iv) transmission system maintenance

for each year 2000 to 2008 on an actual basis, and projected for 2009 – 2011.

Response:

The annual expenditures for the various items are detailed in the tables below. The increases in O&M and capital spend to help illustrate the implications of aging assets, including the general trend of increased capital replacements and O&M required over the period. With over half of the Transmission pipe now over 40 years old, TGI believes addressing the implications of an aging transmission system, through the 2010 and 2011 funding requirements, are prudent and necessary.

It should be noted that operations and maintenance activities are generally performed by the same transmission staff, so historically the distinction between operations and maintenance activities has not always been clearly represented in cost breakdowns. For this reason, the O&M costs represented in the table below need to interpreted with this in mind. There have also been changes in the treatment of certain inspection costs between capital and O&M. As well, Company reorganizations prior to 2004 make comparisons for 2000-2003 O&M difficult so the numbers are representative for magnitude only. Since 2007, corrective and preventative maintenance has been more clearly separated out from operations and is represented in the table as maintenance.

As indicated in the RRA Appendix F page 14 Transmission is now in the process of enhancing its asset management disciplines within Transmission, with one focus being improvement of activity-based accounting and reporting.

Table 1

Transmission System Totals	($000,000)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Replacement Activity	Capital	12.1	5.4	10.3	11.4	6.1	4.4	5.5	6.4	15.1	36.3	11.5	24.6
Reinforcement Activity													
Note 1	Capital	347.5	36.6	16.6	1	-0.3	0.1	-0.1	-0.2		0.5	0.5	0 .5
Inspections	Capital	4.8	9.8	8.3	12.3	2.9	4.2	-0.3				1.2	0.6
Inspections	O&M	0.3	0.5	0.4	0.4	2.8	4.6	4.4	3.7	4.7	5.9	3.7	3.8
Maintenance	O&M	0.5	0.9	1.1	1.1	2.2	2	1.8	1.9	2.1	2.1	2.2	2.2
Operations	O&M	7.3	7.7	7.7	6.9	7.7	7.6	6.5	7.3	7.2	8	10.7	11.4

Note 1: System reinforcement activity relates to capacity upgrades

Table 2.

Inspection Cost Breakdown	($000,000)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Capital Inspections Notes 2,3	*Capital*	*4.8*	*9.8*	*8.3*	*12.3*	*2.9*	*4.2*	*-0.3*				*1.2*	*0.6*
(TPIP ILI) Notes 3,4	*O&M*					*0.8*	*1.4*	*1.3*	*0.8*	*0.7*	*0.3*		
(TPIP other) Notes 3,5	*O&M*					*1.7*	*2.9*	*2.7*	*2.5*	*3.5*	*5.1*	*3.2*	*3.3*
(other)Note 6	*O&M*	*0.3*	*0.5*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.4*	*0.5*	*0.5*	*0.5*	*0.5*
Total Inspections	*Capital & O&M*	5.1	10.3	8.6	12.8	5.7	8.9	4.1	3.7	4.7	5.9	5.9	4.4

Note 2: Capital Inspections 2000-2006 per TPIP CPCN, 2000-2003 includes retrofits for ILI capability plus ILI inspections, for 2004-2005, just retrofits. 2006 is a previous year credit offset.
Note 3: TPIP Activities included in O&M beginning in 2004 per Order No. G-80-03
Note 4: Major inspections costs now capital pursuant to IFRS.
Note 5: TPIP other includes Class Location Surveys, Natural Hazards, Cathodic Protection, Direct Assessment and Bridge Crossings.
Note 6: ROW Patrols, Leak Surveys, plus some Class Location Surveys, Geotechnical Surveys, Direct Assessment and Bridge Crossings outside of TPIP funding.

Table 3.

O&M Cost Breakdown	($000,000)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Maintenance	*O&M*	*0.5*	*0.9*	*1.1*	*1.1*	*2.2*	*2*	*1.8*	*1.9*	*2.1*	*2.1*	*2.2*	*2.2*
O&M Inspections	*O&M*	*0.3*	*0.5*	*0.4*	*0.4*	*2.8*	*4.6*	*4.4*	*3.7*	*4.7*	*5.9*	*3.7*	*3.8*
Operations Note 7	*O&M*	*7.3*	*7.7*	*7.7*	*6.9*	*7.7*	*7.6*	*6.5*	*7.3*	*7.2*	*8*	*10.7*	*11.4*
Total O&M *Note 8*		8.1	9.1	9.2	8.4	12.7	14.2	12.7	12.9	14	16	16.5	17.4

Note 7: Because other IMP activities such as vegetation management activities for ROW and stations and security costs are recorded as operations costs, the table shows total O&M costs plus a derived total for operations after subtracting maintenance and inspections as defined above.
Note8: TPIP Activities included in O&M beginning in 2004 per Order No. G-80-03, which accounts for jump between 2003 and 2004

26.0 Reference: Part III, Section B, p. 170, Table B-1-18, Marketing and Business Development O&M

26.1 Please confirm that the overall time pattern of these expenses is consistent with the financial incentives a utility has under a multi-year PBR, i.e., early nominal decreases followed by significant nominal increases as the end of the PBR is approached.

Response:

All seven departments in TGI experienced a significant reduction in O&M expenses in 2004 and 2005 as the benefits of the Utilities Strategy Project were realized. Subsequent years showed the upward cost pressure of both labour and non-labour inflation and the external factors described in Part III, Section A of the Application, to varying degrees in different departments. To compare O&M costs across the years, a more appropriate comparison than nominal O&M is to look at O&M on both an inflation-adjusted and a per customer basis. O&M expenses on these bases have remained relatively flat or in fact decreased, and have not exhibited the described time pattern of expenses. TGI has managed the O&M costs for the equal benefit of customers and the Company during the PBR Period.

In the Marketing and Business Development department, specific cost drivers and their impacts on O&M have been described on pages 170 to 172 of the Application.

27.0 Reference: Part III, Section B, p. 173, Table B-1-19, Business and IT O&M

27.1 Please confirm that the overall time pattern of these expenses is consistent with the financial incentives a utility has under a multi-year PBR, i.e., early nominal decreases followed by significant nominal increases as the end of the PBR is approached.

Response:

All seven departments in TGI experienced a significant reduction in O&M expenses in 2004 and 2005 as the benefits of the Utilities Strategy Project were realized. Subsequent years showed the upward cost pressure of both labour and non-labour inflation and the external factors described in Part III, Section A of the Application, to varying degrees in different departments. To compare O&M costs across the years, a more appropriate comparison than nominal O&M is to look at O&M on both an inflation-adjusted and a per customer basis. O&M expenses on these bases have remained relatively flat or in fact decreased, and have not exhibited the described time pattern of expenses. TGI has managed the O&M costs for the equal benefit of customers and the Company during the PBR Period.

In the Business and IT Services department, specific cost drivers and their impacts on O&M have been described on pages 173 to 174 of the Application.

28.0 Reference: Part III, Section B, p. 174, Table B-1-20, Human Resources and OGD O&M

28.1 Please confirm that the overall time pattern of these expenses is consistent with the financial incentives a utility has under a multi-year PBR, i.e., early nominal decreases followed by significant nominal increases as the end of the PBR is approached.

Response:

All seven departments in TGI experienced a significant reduction in O&M expenses in 2004 and 2005 as the benefits of the Utilities Strategy Project were realized. Subsequent years showed the upward cost pressure of both labour and non-labour inflation and the external factors described in Part III, Section A of the Application, to varying degrees in different departments. To compare O&M costs across the years, a more appropriate comparison than nominal O&M is to look at O&M on both an inflation-adjusted and a per customer basis. O&M expenses on these bases have remained relatively flat or in fact decreased, and have not exhibited the described time pattern of expenses. TGI has managed the O&M costs for the equal benefit of customers and the Company during the PBR Period.

In the Human Resources and Operations Governance department, specific cost drivers and their impacts on O&M have been described on pages 174 to 175 of the Application.

29.0 Reference: Part III, Section B, p. 176, Table B-1-22

29.1 Please provide a breakout of the nominal O&M costs associated with Regulatory Affairs alone if possible.

Response:

Nominal O&M	Decision	Actual					Projection
($ millions)	2003	2004	2005	2006	2007	2008	2009
Regulatory Affairs	2.9	2.6	2.9	2.5	2.8	3.6	3.9

30.0 Reference: Part III, Section B, p. 177, Capital 2003 to 2009

30.1 Please identify the projects associated with any capital savings achieved during this period where the savings are due to project deferment. Please indicate the savings associated with each deferred project.

Response:

As stated in the response to BCOAPO IR 1.5.2, TGI believes deferring capital expenditures without jeopardizing the safety and reliability of the system is prudent and appropriate. Through the introduction of the Capital Management Office which was created to exercise a greater level of discipline on capital spending, TGI has been able to not only defer the timing of expenditures but also reduce the level of capital spend required to safely and reliably operate the system. It is through this process that TGI has been able to and will continue in the future to manage the level of capital spending on behalf of customers.

TGI does not specifically track all projects that have been deferred in timing. As a result, it is unable to report the savings associated with deferred projects.

For capital PBR savings, please refer to BCOAPO IR 1.5.2.

30.2 Please identify the projects associated with any capital savings achieved during this period where the savings are due to the project being undertaken and completed under budget. Please indicate the savings associated with each such project that came in under budget.

Response:

Below is a summary of major projects over $1 million during the PBR period where capital savings were achieved. For purposes of completing this table, capital savings has been defined as completed cost being less than the budget. However, for purposes of calculating savings under the PBR formula for non-CPCN projects, the savings were determined by comparing the formula based amount (not the budget) to the completed costs.

Summary of Major Capital Projects

Project	Budget	Completed Cost	Savings	
LNG Coldbox Upgrade	4.1	4.0	0.1	
Café	1.8	1.4	0.4	
IT Infrastructure Network Evergreening	1.2	0.4	0.8	Note 3
Order Fulfillment Enhancements	1.1	0.5	0.6	Note 4
CPCN				
Commercial Unbundling	7.0	6.2	0.8	
Residential Unbundling	12.1	10.7	1.4	
Distribution Mobile Solution	6.2	6.1	0.1	
Vancouver Low Pressure Replacement	23.1	17.5	5.6	

Notes:
1. Expenditures in $ millions
2. Figures exclude AFUDC
3. IT Infrastructure Network Evergreening is an annual project with $.4 million incurred in 2007. Shifting business priorities resulted in total spending of $1.1 million during the 2005 - 2007 period.
4. Some Order Fulfillment Enhancements were integrated with the Distribution Mobile Solution project to be more cost effective.

Project	Budget	Completed Cost	Savings
LNG Coldbox Upgrade	4.1	4.0	0.1
Café	1.8	1.4	0.4
Order Fulfillment Enhancements	1.1	0.5	0.6
IT Infrastructure Network Evergreening	1.2	0.4	0.8
CPCN			
Commercial Unbundling	7.0	6.2	0.8
Residential Unbundling	12.1	10.7	1.4
Distribution Mobile Solution	6.2	6.1	0.1
Vancouver Low Pressure Replacement	23.1	17.5	5.6

Notes:
1. Expenditures in $ millions
2. Figures exclude AFUDC

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CPCN				
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Residential Unbundling	12.1	10.7	1.4	
Distribution Mobile Solution	6.2	6.1	0.1	
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Notes:
1. Expenditures in $ millions
2. Figures exclude AFUDC
3. IT Infrastructure Network Evergreening is an annual project with $.4 million incurred in 2007. Shifting business priorities resulted in total spending of $1.1 million during the 2005 - 2007 period.
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CPCN				
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Residential Unbundling	12.1	10.7	1.4	
Distribution Mobile Solution	6.2	6.1	0.1	
Vancouver Low Pressure Replacement	23.1	17.5	5.6	

Notes:
1. Expenditures in $ millions
2. Figures exclude AFUDC
3. IT Infrastructure Netowrk evergreening is an annual project. $1.1 million reflects total costs for the 2005 - 2007 period discussed in the 2005 Annual Review.
4. Some Order Fullfilment Enhancements were integrated with the Distribution Mobile Solution project to be more cost effective.

30.3 Please identify any projects associated with any savings due to the fact that a "smarter," less expensive project was substituted for a scheduled project. Please Provide the savings associated with each such instance.

Response:

This is not tracked as before a capital project is scheduled and included in the capital budget, it undergoes a review and approval process to evaluate the merits of the funding request. Please refer to TGI's response to BCUC IR 1.164.2 for details of the Capital Approval policy. The projects that then end up in the capital budget represent projects that meet requirements and are the most cost effective. The project evaluation process established during the PBR period remains in place, and TGI intends to continue exercising diligence in reviewing capital projects for potential savings.

31.0 Reference: Part III, Section B, p. 179 and Table B-1-25, Capital Savings

31.1 Please respond to the comment that given the way capital savings were measured And given the "glide path" mechanism for phasing out such savings, TGI had a Financial incentive to underspend with respect to the formulaically determined rate base amounts during the PBR Plan, regardless of what prudent, long-term asset management might otherwise indicate.

Response:

TGI has managed assets prudently throughout the PBR period and will continue to do so. The elements of TGI's 2004 - 2007 PBR Plan and 2008 - 2009 PBR Plan Extension were established through a public hearing process that culminated in a negotiated settlement process and a negotiated settlement agreement that was approved by the Commission. The PBR Plan contained a variety of terms and mechanisms designed to encourage TGI to find efficiencies, among which was a capital incentive mechanism that set allowed base capital spending on a formula basis and an end-of-term phase-out mechanism permitting TGI to retain a decreasing portion of the capital efficiency benefits in the two years following the end of the PBR. In order to provide assurance to customers that service quality was being maintained during the PBR term a series of ten Service Quality Indicators (SQIs) and two directional indicators were established, some of which pertained to the integrity and functioning of the physical assets and systems comprising the Company's rate base. The PBR Plan also included thorough reporting provisions to keep stakeholders apprised of the Company's operations and the results of the PBR through Annual Reviews, a Mid-Term Assessment Review and the Customer Advisory Committee meetings.

All of these provisions were intended to work together to find a balance between TGI seeking efficiencies and cost savings while at the same time ensuring that system integrity and reliability and customer service were maintained. Although the capital incentive elements of the PBR might provide the superficial appearance of incenting the utility to cut capital costs in a manner that could negatively affect system integrity and reliability in the longer term TGI believes that the other safeguard mechanisms (SQIs, Annual Reviews, etc.) included in the PBR provided appropriate counterbalance to these concerns. TGI also points to its strong corporate commitment to public safety and operational excellence as another indicator that such a course of action would not occur. (See page 99-101 of the Application for a summary of TGI's internal commitment to operational excellence). A final point is that TGI is subject to many stringent external codes and standards designed to promote safe operation of the natural gas system and protection of the environment. These external drivers provide further safeguards against the possibility of capital cost cutting leading to the compromising of system safety and reliability.

32.0 Reference: Part III, Section C, Tab 2, p. 220, Table C-2-1, Revenue Requirements

32.1 Please provide a Table, broken down by category similar to the referenced Table showing projected actual 2009 results, in total rather than changes with respect to a year, e.g., show the projected actual total 2009 rate base equity finance expense, the expected actual total 2009 debt finance expense, the expected actual 2009 utility O&M expense, etc., augmenting the 2009 column with 2010 and 2011 columns presented similarly to 2009.

Response:

The table provided in C-2-1 was designed to explain the year over year changes that contribute to the revenue deficiency or surplus as they relate to existing 2009 rates and may not be the ideal presentation format to compare the total amounts. Therefore, a variation of Table C-2-1 below breaks down the required gross margin for projected 2009 and forecast 2010 and 2011, also showing the calculation of the revenue deficiency for 2010 and 2011:

(in $ Millions)

Line No.	Particulars	2009 Projected	2010 Forecast	2011 Forecast	Reference
(1)	(2)	(3)	(4)	(5)	(6)
1	Gross O&M Expense	$ 193.3	$ 209.6	$ 219.1	- Tab C-13, Schedule 28, (Line 19 + Line 21)/1000
2	Operating Leases	1.8	-	-	- Tab C-13, Schedule 72, 4 & 5, Column 5, Line 24/1000
3	Capitalized Overhead	(28.1)	(16.8)	(17.5)	- Tab C-13, Schedule 28, Line 22/1000
4	Net O&M Expense	167.0	192.8	201.6	
5	Property & Other Tax Expense	47.6	49.2	50.2	- Tab C-13, Schedule 72, 4 & 5, Column 5, Line 25/1000
6	Depreciation Expense	79.8	106.2	109.0	- Tab C-13, Schedule 33 & 34, Columns 2 & 3, Line 6/1000
7	Amortization Expense	(0.1)	(2.4)	1.5	- Tab C-13, Schedule 33 & 34, Columns 2 & 3, Line 11/1000
8	Other Revenue	(20.9)	(22.4)	(24.4)	- Tab C-13, Schedule 26 & 27, Columns 2 & 3, Line 24/1000
9	Income Tax Expense	23.0	31.6	31.7	- Tab C-13, Schedule 72, 4 & 5, Column 5, Line 31/1000
10	Equity Finance Expense	98.3	110.1	115.4	- Tab C-13, Schedule 75, 62 & 63, Column 6, Line 12/1000
11	Debt Finance Expense	108.2	75.2	77.7	- Tab C-13, Schedule 75, 62 & 63, Column 6, (Line10 + Line 11)/1000
12					
13	Required Gross Margin	502.9	540.3	562.8	
14					
15	Gross Margin at Existing Rates		512.4	512.9	- Tab C-13, Schedule 4 & 5, Column 2, Line 21/1000
16					
17	Revenue Deficiency/(Surplus)		**27.9**	**49.8**	= Line 13 - Line 15

33.0 Reference: Part III, Section C, Tab 2, p. 222, Tables C-2-2 and C-2-3

33.1 Please provide Tables similar to those referenced that show expected actual total 2009 spending for each category, along with expected actual total 2010 and 2011 spending for each category.

Response:

Table C-2-2

The reference information for the table below can be found in Section C Tab 13 of the Application, Schedules 16 & 17 and Schedules 26 & 27.

	($ millions)		
	2009	2010	2011
Residential Revenue	883.5	897.4	891.8
Commercial Revenue	461.7	487.2	494.6
Other Core Customer Revenue	32.2	30.1	29.8
Transportation Revenue	74.1	73.4	73.4
SCP Revenue	11.1	12.8	14.8
Other Revenue	9.8	9.6	9.6
Total Revenue	1,472.4	1,510.4	1,513.9

Table C-2-3

Table C-2-3 was provided with the intention of explaining the incremental changes and cost pressures for 2010 and 2011 as they compare to 2009 gross O&M. Total O&M for any given year cannot be categorized into this incremental view since there is no base against which to compare incremental changes. However, schedules 29 and 30 in Section C tab 13 provide a comprehensive breakdown of the total gross O&M expense for 2009-2011, including a view of how much of the total is related to labour costs.

34.0 Reference: Part III, Section C, Tab 3, Energy Efficiency and Conservation Programs

34.1 Please provide a Table showing, by program, total capital spending, operating expenditures, amount of spending targeted at low-income consumers, expected savings for low income consumers, and expected cost recovery from low-income consumers for 2010 and 2011.

Response:

Please refer to Table C-3-3 on page 229 of this Application for information regarding spending by program; expenditures targeted to energy efficiency improvements for the low-income housing sector are included in the "Joint Initiatives" section of this table. As the programs for the low-income housing sector are under development at the time of writing, final budgets for same and expected savings for low-income customers are not available at this time. As was noted in the response to BCOAPO IR 1.21.3 and 1.21.4[5] on the Terasen Utilities' EEC Application, TGI does not collect information on its customers' incomes, and therefore cannot isolate these customers in order to calculate cost recovery from these specific customers. As per BCUC Order No. G-36-09, all EEC expenditures will be treated as equivalent to capital, therefore there will be no O&M ("operating") expenditures.

[5] Terasen Utilities' response to BCAOPO IR 1 on Terasen's EEC Application pp. 30-31.

35.0 Reference: Part III, Section C, Tab 4, Energy Forecast Methodology

35.1 Please confirm that TGI has made no changes to its approved forecasting methodology. If unable to so confirm, please provide a list of changes and the impacts of each on the forecasts.

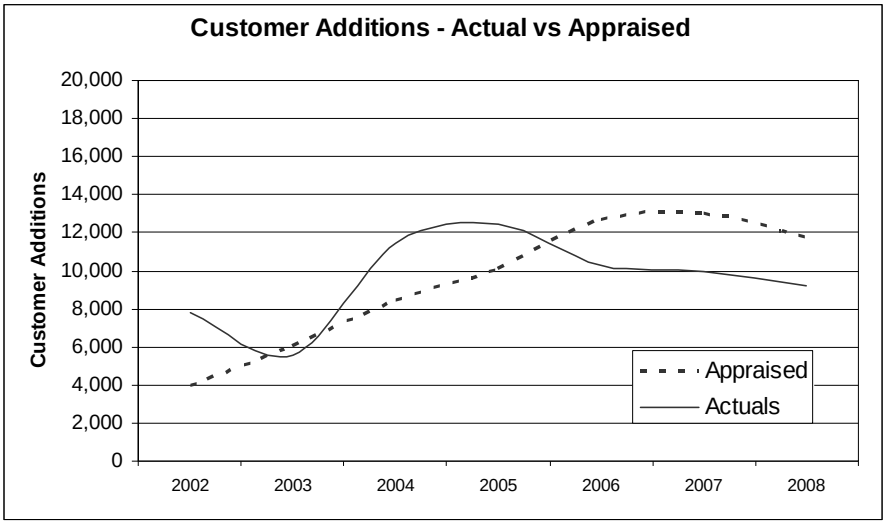
Response:

Please see TGI's response to BCUC IR 1.39.1.

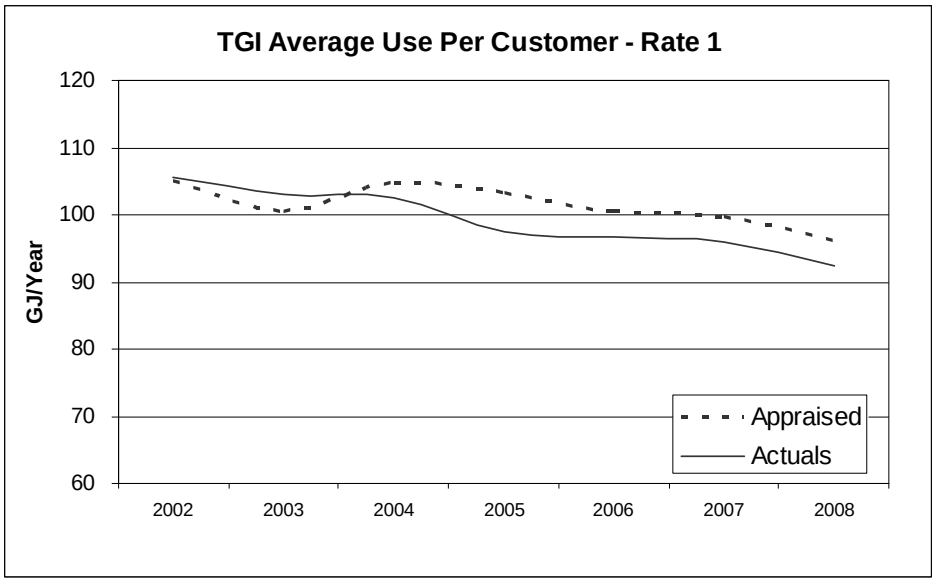
35.2 For each year, 2002-2008 inclusive, please provide a table showing forecasted and actual customer additions, average use per customer, and industrial demand.

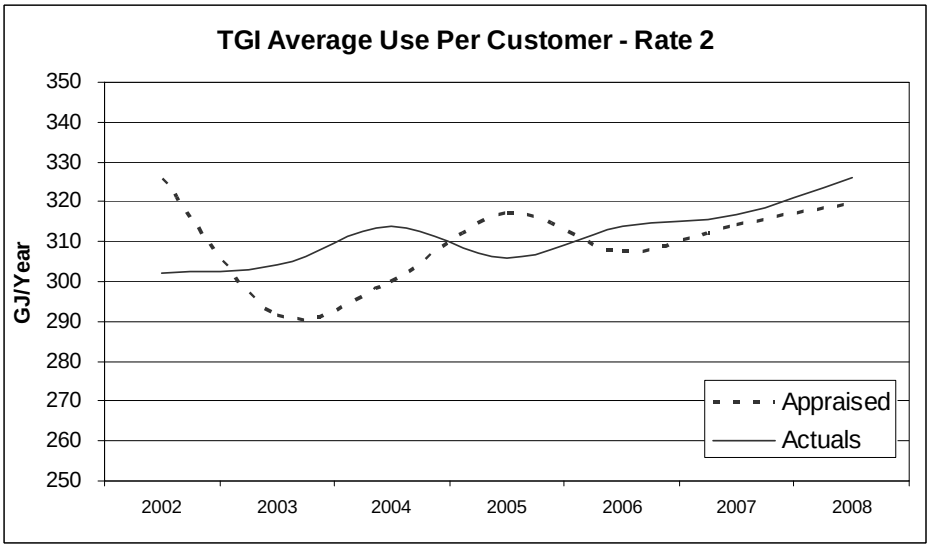
Response:

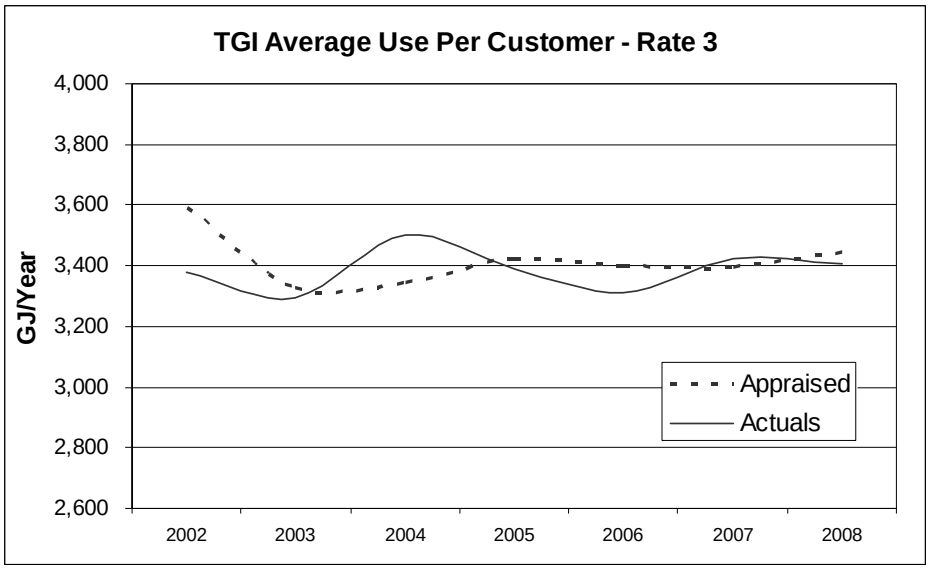
The following chart illustrates the appraised and actual results for Customer Additions over the period 2002 to 2008.

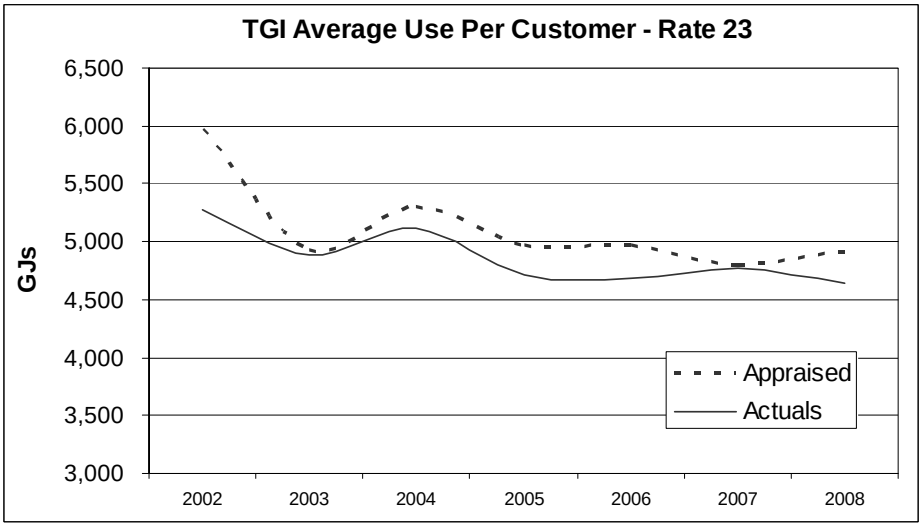


The following chart illustrates the appraised and actual results for Average Use Per Customer over the period 2002 to 2008, for Rate 1, 2, 3, and 23 customers.

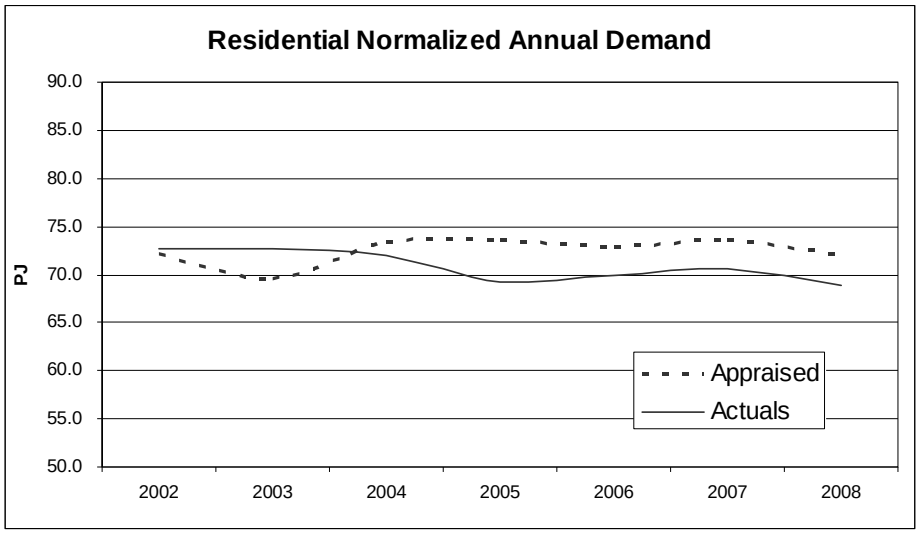

TGI Average Use Per Customer - Rate 1
GJ/Year
120
110
100
90
80
70
60
2002
2003
2004
2005
2006
2007
2008
Appraised
Actuals

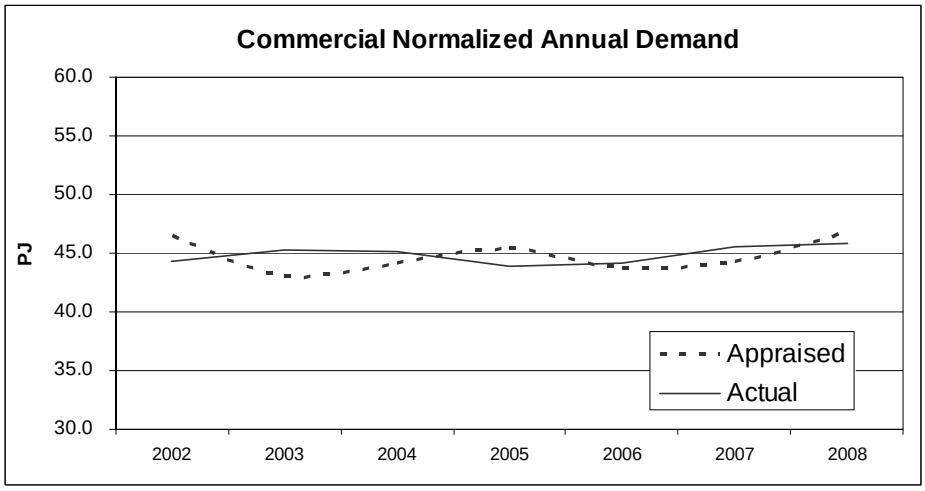

TGI Average Use Per Customer - Rate 2
GJ/Year
350
340
330
320
310
300
290
280
270
260
250
2002
2003
2004
2005
2006
2007
2008
Appraised
Actuals

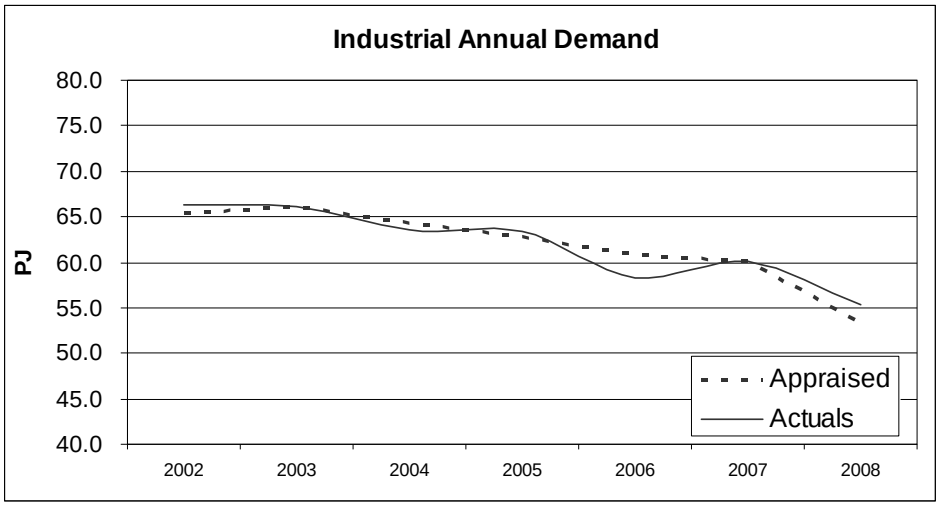




The following charts illustrate the appraised and actual total energy demand over the period 2002 to 2008 for Residential, Commercial and Industrial customers.


Residential Normalized Annual Demand
90.0
85.0
80.0
75.0
70.0
65.0
60.0
55.0
50.0
PJ
2002
2003
2004
2005
2006
2007
2008
Appraised
Actuals


Commercial Normalized Annual Demand
60.0
55.0
50.0
45.0
40.0
35.0
30.0
PJ
2002
2003
2004
2005
2006
2007
2008
Appraised
Actual


Industrial Annual Demand
PJ
80.0
75.0
70.0
65.0
60.0
55.0
50.0
45.0
40.0
2002
2003
2004
2005
2006
2007
2008
Appraised
Actuals

36.0 Reference: Part III, Section C, Tab 6, pp. 351-352, Codes and Regulations

36.1 For each code identified in Tables C-6-4 and C-6-5, please indicate when the code became effective.

Response:

Code/Regulation	Comments
B.C. Oil and Gas Commission Act (1998-07-30) • B.C. Pipeline Act (circa 1950 - current edition 1996) • B.C. Pipeline Regulations (circa 1950 - current edition 1998-10-23)	Will be replaced by the Oil and Gas Activities Act
BC Safety Authority • Safety Standards Act (2003-05-29) • Gas Safety Regulations (2004-04-01)	Recent amendment changes (2008-04-01) to Procedures for Excavations sections requires a gas company to respond in 2 business days, rather than 3 to the excavator with gas system information. See Appendix F8, pgs 3-4 of the Application for more explanation on the impacts of this change.
CSA Z246 - Security Management For Petroleum and Natural Gas Industry Systems Anticipated release: 2009-10	NEW - impacts not yet known. In 2009 meetings with the OGC and NEB, they both say this will be adopted into regulation.
CSA Z276 - Liquid Natural Gas Production, Storage and Handling (1972 – currently in 8th edition 2007)	
CSA Z662 - Oil and Gas Pipeline Systems (1994 - currently in 5th edition 2007) Previously CSA Z184 (1968)	"Pipeline Regulation, Section 12 (1): "Except as otherwise provided in this regulation, the standard governing the design, fabrication, installation, testing, operation, maintenance, repair or deactivation of onshore and offshore gas, oil, oilfield water and steam pipelines, including flow, gathering and transmission lines, is CSA Standard Z662 and, in cases where only partial or imperfect provisions exist in CSA Standard Z662, the chief inspecting engineer may establish provisions to meet those requirements."
CSA Z662 - Annex A: Safety and Loss Management System Release date 2008 (in 2007 edition)	While Annex A is not mandatory, clause 10.2 of CSA Z662-07 requires a company to have a safety and loss management program. Whenever we refer to "Annex A",

Code/Regulation	Comments
Note to CSA Z662-2007 Clause 10.2.1 on pg 177: *"The time required to develop and implement a safety and loss management system depends on the size and complexity of the operating company and the pipeline system and may take up to 2 years or more."*	we are referring to this clause as Annex A provides a framework for a safety and loss management program. This requirement is new during the later part of the PBR period, showing up in the 2007 edition, released in 2008, but allows companies a grace period to achieve compliance. See Appendix F8, pgs 22-29 of the Application for more explanation on the impacts of this change.
CSA Z662 - Annex M: Gas Distribution Integrity Management Guidelines Release date 2008 (in 2007 edition)	Not mandatory, but adopted by Terasen Gas as a framework for Distribution Assets. Virtually identical to Annex N but for distribution assets.
CSA Z662 - Annex N : Guidelines for Pipeline Integrity Management Programs Release date 2008 (in 2007 edition)	On 2006-08-25 the OGC issued Information Letter #OGC 06-12 adopting CSA Standard Z662-03, Oil and Gas Pipeline Systems, Annex 'N': Guideline for Integrity Management Programs, requiring owners and operators of pipelines to develop and implement an integrity management program. Terasen Gas has been working since 2006 to prepare for the OGC audit anticipated later in 2009. See Appendix F8, pgs 5-10 of the Application for more explanation on the impacts of this change. It is also discussed in the responses to BCUC IR 1.126.1-3. All pipelines, regulated pursuant to the ***Oil and Gas Commission Act***, are now required to have a documented and effective pipeline integrity quality management system put into place. The system must include all pipe and piping along or within the respective right-of-way's, and all pipeline facilities. Expectations: o Phase 1, scheduled to be completed by Mar 1/07 ▪ Companies are required to develop and submit to the OGC for acceptance the following: i. a company specific pipeline integrity management framework; ii. comparison of new requirements to current program, including timelines for integration of new requirements; iii. evaluation of program gaps and

Code/Regulation	Comments
	identification of remedies; and iv. development of internal change management processes. ▪ The OGC will monitor and audit Phase 1 activities o Phase 2, scheduled to be completed by Sep 1/07 ▪ Companies are required to develop and submit to the OGC for acceptance the following: • implementation strategies for activities identified in phase 1. ▪ OGC will monitor and audit phase 2 activities. o Phase 3, scheduled to be completed by Oct 1/09 ▪ Companies are expected to complete pipeline assessments and implement pipeline integrity quality management system. ▪ The OGC will monitor and audit phase 3 activities. o Phase 4, scheduled to be completed by Oct 1/11 ▪ The OGC will have completed one full cycle of auditing on all company pipeline integrity quality management systems
CSA Z1000 (2006)	Not mandatory but adopted by Terasen Gas as the framework which best satisfies WorkSafeBC's compliance requirements. (Occupational Health and Safety Regulation - Workers Compensation Act - 1996)
Environmental Management Act (2003-10-23)	
Power Engineers and Pressure Vessel Safety Act (2004-04-01)	Working towards compliance through 2009-2010 period. See Appendix F8, pg 31 of the Application for more explanation on the impacts of this change.

To ensure ongoing compliance to existing codes and anticipated new or changed codes, additional operating and maintenance funding is required. There are 4 main drivers to the increases:

- Inflationary costs i.e. increased external labour costs, materials costs, etc;
- Growth i.e. more services to inspect/maintain, more ROW to clear, more external activity to control/monitor;
- Asset age which increases risk profile, i.e. more frequent inspections, more unplanned maintenance (repair), more replacements; and
- New or changed code requirements.

The reasons for incremental increases are outlined in Appendix F-8 of the Application.

When new code requirements occurred during the PBR period, Terasen Gas worked to achieve compliance, and shifted funding from lower risk items to achieve this. However, this shift cannot be continued indefinitely as low risk items will eventually rise to medium and high levels. For this reason and the 4 cost drivers identified above, Terasen Gas believes the incremental funding as outlined in Appendix F, page 1 of the Application are necessary and prudent.

36.2 Please indicate whether there have been any savings, related to productivity improvements or other, related to code compliance over the period 2003-2008, or expected for 2009-2011.

Response:

New codes typically require additional activities to meet compliance and result in incremental costs and not savings. When new code requirements occurred during the PBR period, Terasen Gas worked to achieve compliance, and shifted funding from lower risk items to achieve this. However, this shift cannot be continued indefinitely as low risk items will eventually rise to medium and high levels. Please see the response to BCOAPO IR 1.36.1 in this regard.

However, we are always looking for ways to improve the methods with which we achieve code compliance.

For example we have noticed since moving to Inline Inspection (ILI) tools that we can now perform inspections based on risk assessment and not on a rigid time-driven schedule. Also as a result of ILI tools our inspection digs have decreased. We have reduced preventive maintenance activities based on asset performance and risk analysis, including station overhauls and meter set pm's where specific regulators are installed. All of this has been done while still meeting Code requirements. However, as we have funding challenges in other integrity areas based on our risk assessments, we shift funding to these other activities as required.

Terasen Gas is committed to a continuous improvement approach to its operations, and will continue to look for productivity improvements while applying a risk based methodology for allocating funding to achieve a safe and reliable natural gas service to its customers.

37.0 Reference: Part III, Section C, Tab 6, O&M General

37.1 For each year 2002-2008 inclusive, please provide the forecast and actual O&M expense broken down by department along with a variance explanation.

Response:

Department	2002*		2003		2004		2005	
(millions)	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast
Distribution			30.8	31.5	31.4	30.3	32.8	31.8
GS&T			14.7	9.5	13.4	15.1	15.1	15.7
Marketing & Development			59.0	59.5	58.4	59.7	58.1	61.3
B&ITS			31.4	32.6	30.4	31.8	32.6	33.9
HROG			8.0	7.6	6.0	5.9	5.9	6.3
Finance and Regulatory Affairs			6.8	7.3	6.6	6.8	7.4	7.5
President			22.8	18.8	35.1	25.2	18.9	21.5
Total Gross O&M	**170.1**	**164.2**	**173.5**	**166.7**	**181.3**	**174.9**	**170.8**	**177.9**
Variance (Actual vs. Forecast)		**(5.9)**		**(6.8)**		**(6.3)**		**7.1**

Department	2006		2007		2008	
(millions)	Actual	Forecast	Actual	Forecast	Actual	Forecast
Distribution	31.7	31.3	33.4	32.8	37.0	33.7
GS&T	13.7	15.4	13.7	16.0	14.7	16.2
Marketing & Development	60.9	62.1	60.7	62.8	63.1	64.2
B&ITS	33.7	34.6	35.4	35.4	35.7	35.8
HROG	6.4	6.5	7.0	7.1	7.3	7.3
Finance and Regulatory Affairs	7.1	7.2	7.8	8.3	8.7	9.1
President	25.7	24.8	21.1	20.9	19.3	20.5
Total Gross O&M	**179.2**	**181.8**	**179.0**	**183.3**	**185.7**	**186.8**
Variance (Actual vs. Forecast)		**2.6**		**4.3**		**1.0**

**Due to significant restructuring, the 2002 department view is not comparable to subsequent years on a line by line basis.*

Legend
GS&T: Gas Supply and Transmission
B&ITS: Business and Information Technology Services
HROG: Human Resources and Operations Governance
TPIP: Transmission Pipeline Integrity Program

Please find below a summary of the variances for each year:

2002 Variance Explanation

This unfavourable variance was primarily driven by the following factors: $2.4 million higher bad debt expenditure, $2.4 million attributable to higher stock option expense and $1 million related to higher IT Application and Infrastructure expenditure.

2003 Variance Explanation

This unfavourable variance was attributable to $4.9 million USP restructuring costs and $1.2 million higher employee incentive and insurance expenditure.

2004 Variance Explanation

The unfavourable variance was attributable to $9.6 million USP restructuring costs, partially offset by under spend of $1.5 million in TPIP activities due to a late start up of the program, $0.8 million lower bad debt expenditure and $0.3 million under spend due to lower volumes of own use fuel gas and electricity together with higher recoveries received from the sale of LNG to a third party.

2005 Variance Explanation

By 2005 the USP restructuring initiative had been completed and the benefits of a single management team and shared back office support structure enabled lower O&M expenditure. Other savings also realized were $2.2 million of reduced bad debt expenditure and $1.5 million due to lower employee incentives and OPEB than anticipated.

2006 Variance Explanation

This favourable variance was due to under spend of $1.1 million in TPIP activities, $1.2 million lower bad debt expenditure and $0.3 million in savings due to lower volumes of own use fuel gas and electricity.

2007 Variance Explanation

This favourable variance was due to under spend in TPIP activities of $1.5 million due to resource constraints, $1.5 million lower bad debt expenditure and $0.5 million under spend of

own use fuel gas and electricity due to lower required volumes and the remaining savings were primarily due to challenges in promptly filling vacant positions.

2008 Variance Explanation

Approximately $2.1 million of the unfavourable in Distribution was due to higher third party un-recovered damage claims together with increased activities in first response standby, leak repairs, snow removal, line locates and leak repairs. This was offset by favourable variances of which $1.2 million was due lower bad debt expenditure, $1.1million due to delays in TPIP and $0.6 million due to lower employee benefit expenditures.

The results demonstrate TGI's ability to manage and control costs for the benefit of customers and the shareholder.

38.0 Reference: Part III, Section C, Tab 9, Capital Expenditures.

38.1 For each year 2002-2008 inclusive, please provide the year-ahead forecasted and actual capital expenditures.

Response:

	2002 Forecast	2002 Actual	2003 Decision	2003 Actual	2004 Forecast	2004 Actual	2005 Forecast	2005 Actual
Category A								
Mains	4.6	4.6	6.0	4.2	4.8	5.3	5.1	7.4
Services	7.2	9.6	10.6	10.1	8.9	13.3	9.4	14.6
New Meters & Meters Recalled	15.7	13.4	16.9	17.5	17.1	15.4	17.8	15.3
Total Category A	**27.5**	**27.6**	**33.5**	**31.8**	**30.8**	**34.0**	**32.3**	**37.3**
Category B								
Transmission Plant	7.5	10.6	8.2	11.4	12.0	7.1	5.4	5.6
Distribution Plant	12.9	10.4	17.2	13.8	13.0	11.0	11.9	10.2
Total Category B	**20.4**	**21.0**	**25.4**	**25.2**	**25.1**	**18.1**	**17.3**	**15.8**
Category C								
IT	17.1	13.9	14.9	10.3	12.0	7.3	11.4	10.6
Non-IT	11.9	10.1	12.1	13.3	12.2	10.9	10.2	12.0
Total Category C	**29.0**	**24.0**	**27.0**	**23.6**	**24.2**	**18.3**	**21.6**	**22.6**
Total	**76.9**	**72.6**	**85.8**	**80.6**	**80.1**	**70.4**	**71.3**	**75.7**

Figures exclude AFUDC and Capitalized Overheads

Notes:
1. Expenditures in $millions
2. Forecast figures are consistent with Annual Review filings.

	2006 Forecast	2006 Actual	2007 Forecast	2007 Actual	2008 Forecast	2008 Actual
Category A						
Mains	6.6	8.1	7.7	8.1	9.5	11.0
Services	12.1	16.4	15.6	17.1	19.4	18.0
New Meters & Meters Recalled	16.2	16.2	16.5	13.7	17.2	14.9
Total Category A	**35.0**	**40.7**	**39.8**	**38.9**	**46.2**	**43.9**
Category B						
Transmission Plant	6.4	8.7	6.4	5.1	11.7	13.3
Distribution Plant	16.9	9.7	8.8	10.4	9.2	8.1
Total Category B	**23.3**	**18.4**	**15.2**	**15.4**	**20.8**	**21.4**
Category C						
IT	11.7	7.8	12.7	4.2	10.7	10.5
Non-IT	10.5	16.6	11.9	14.7	12.3	14.2
Total Category C	**22.2**	**24.5**	**24.7**	**18.8**	**23.0**	**24.7**
Total	**80.4**	**83.6**	**79.7**	**73.2**	**90.1**	**90.0**

Figures exclude AFUDC and Capitalized Overheads

Notes:
1. Expenditures in $millions
2. Forecast figures are consistent with Annual Review filings.

39.0 Reference: Part III, Section C, Tab 9, Section a) (4) p. 463, CPCN

39.1 Please provide a table for the PBR period, all CPCNs forecast under $20M including:

(i) the amount applied for;

(ii) the amount approved; and

(iii) the actual cost.

Response:

Below is a summary of all CPCN forecasts under $20 million for the PBR period. TGI was able to successfully complete all four CPCN projects under the amounts approved by the Commission.

CPCN	Amount Requested	Amount Approved	Actual Cost
Distribution Mobile Solution	6.0	6.6	6.4
Residential Unbundling	12.5	12.5	11.1
Commercial Unbundling	7.2	7.2	6.3
Vancouver Low Pressure Replacement	23.7	23.7	18.0

Notes:
1. The above projects include CPCN projects under $20 million that were initiated and completed during the PBR period.
2. Expenditures in $ millions. Figures include AFUDC
3. Amount approved for Distribution Mobile Solution includes the allowed 10% contingency.

Attachment 2.1

Natural Gas Demand Elasticity

Carol Dahl, Professor and Director
http://www.mines.edu/academic/econbus
cdahl@mines.edu

SCHOOL OF MINES 1874 COLORADO

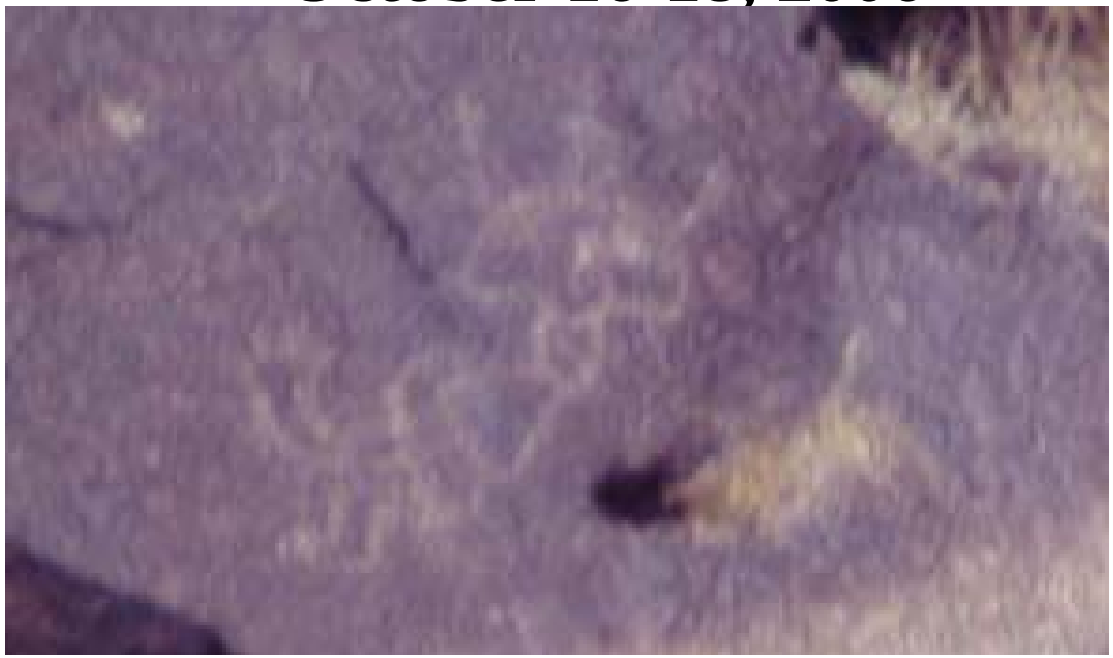
Joint International Graduate Degree Program in Petroleum Economics and Management

Natural Gas Demand Elasticity

with
Mark Chung (Resumé) and Anna Pechatnikov
Mineral Economics Masters Program
Division of Economics and Business
Colorado School of Mines
Golden, CO

for

Gas Forecasters Forum
Hyatt Regency Tamaya Resort and Spa
October 16-18, 2006



Coming Attractions

History and Scope of Project

Elasticities and Their Importance

Methodology

Overview of Historical Issues

Some Sample Elasticities

Meta-Analysis

Progress to Date

Earlier Survey Work

New Work

Where to from Here

Earlier Survey Work
cdahl@mines.edu

Dahl, Carol A. (1995) "Demand for Transportation Fuels: A Survey of Demand Elasticities and Their Components" Journal of Energy Literature, 1(2), Fall.

Dahl, Carol A. (1995) "A Survey of Econometric Estimates of Natural Gas Demand Elasticities: Implications for Natural Gas Substitution in New Zealand" Working Paper, Division of Economics and Business, Colorado School of Mines.

Dahl, Carol A. (1994) "A Survey of Energy Demand Elasticities for the Developing World," Journal of Energy and Development, 18 (I), Autumn. pp. 1-48.

Dahl, Carol A. (1994) "A Survey of Oil Product Demand Elasticities for Developing Countries," OPEC Review, XVIII(1), pp. 47-87.

Dahl, Carol A. (1993) "A Survey of Oil Demand Elasticities for Developing Countries," OPEC Review, XVII (4), Winter, pp. 399-419.

Dahl, Carol A. (1993) "A Survey of Energy Demand Elasticities in Support of the Development of the NEMS" for United States Department of Energy contract De-AP01-93EI23499.

Sterner, Thomas and Dahl, Carol A. (1992) "Modelling Transport Fuel Demand" in International Energy Modelling, London: Chapman and Hall, edited by Thomas Sterner.

Dahl, Carol A. and Sterner, Thomas (1991) "Analyzing Gasoline Demand Elasticities: A Survey," Energy Economics, July, (3):203-210.

Dahl, Carol A. and Sterner, Thomas (1991) "A Survey of Econometric Gasoline Demand Elasticities," International Journal of Energy Systems, 11(2):53-76.

Dahl, Carol A. (1986) "Gasoline Demand Survey," Energy Journal, Vol. 7(1), pp. 67-82.

Reports to Date

Dahl, Carol A. (forthcoming) Oil and Oil Product Demand for *Encyclopedia of Hydrocarbons*. Published by the *Istituto della Enciclopedia Italiana Treccani,* Rome Italy. (English and Italian) 130 studies since 1990

Dahl, Carol, Yris Olaya, and Christopher Valdez (2005) U. S. Demand for Natural Gas in a Global Context in *Globalization of Energy Markets, Technology, Sustainability,* 29th IAEE Conference, Taipei, Taiwan, June 3-6. (27 studies since 1990)

Dahl, Carol and Carlos Roman (2004) "Energy Demand Elasticities Fact or Fiction? A Survey Update," in *Energy, Environment and Economics in a New Era,* 24th Annual North American Conference of the United States and International Association for Energy Economics (USAEE/IAEE), Washington, DC. July 7-10. (190 studies since 1990)

Dahl, Carol A. (2006) Survey Update of Gasoline Demand Elasticitie, Draft, Mineral Economics Program, dolorado School of Mines, Golden, CO.

Funding Sources – Original

Original Survey Work

- **Resources for the Future**
- **U.S. Department of Energy**
- **ARCO**
- **Sweeney – Stanford University**

Funding Sources – Update

Saudi ARAMCO

ENI – Oil and Products

Osinerg – Peruvian Regulatory Agency

OPEC Secretariate

U.S. EPA

Global Energy Decisions – U. S. Natural Gas

Xcel – Electricity Demand

American Petroleum Institute – Gasoline

U.S. EIA/DOE – Heating Fuels

Work In Progress

Ph. D. Students

- **Olaya – World LNG market**
- **Yusgiantoro – Asia Pacific Gas Market**
- **Al Dossary – Demand for Transportation Fuel**
- **Hodge – California Wholesale Electricity Markets**

Scope of Study - Critical Review
All econometric demand elasticities

All countries - all products

- **>1400 studies**

Levels of aggregation

- **E, C, El, O, Ng, Biomass**
- **O – tr & ntr**
- **O – G, K, D, Fo-lt, Fo-hv, LPG**
- **Sector r, c, i, e, tr, ii**

Ng – 156

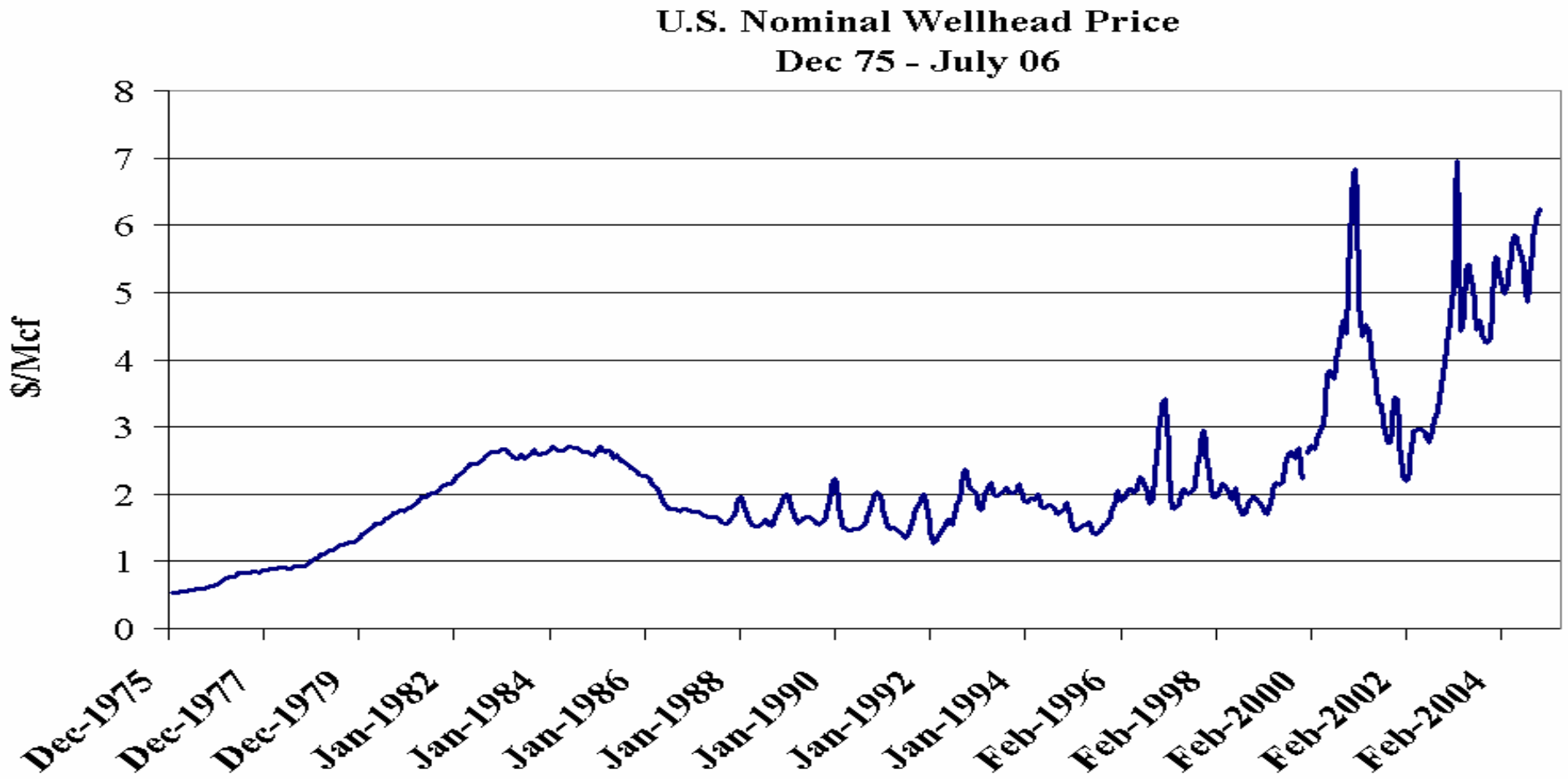
Ng – US - 89

On line data base

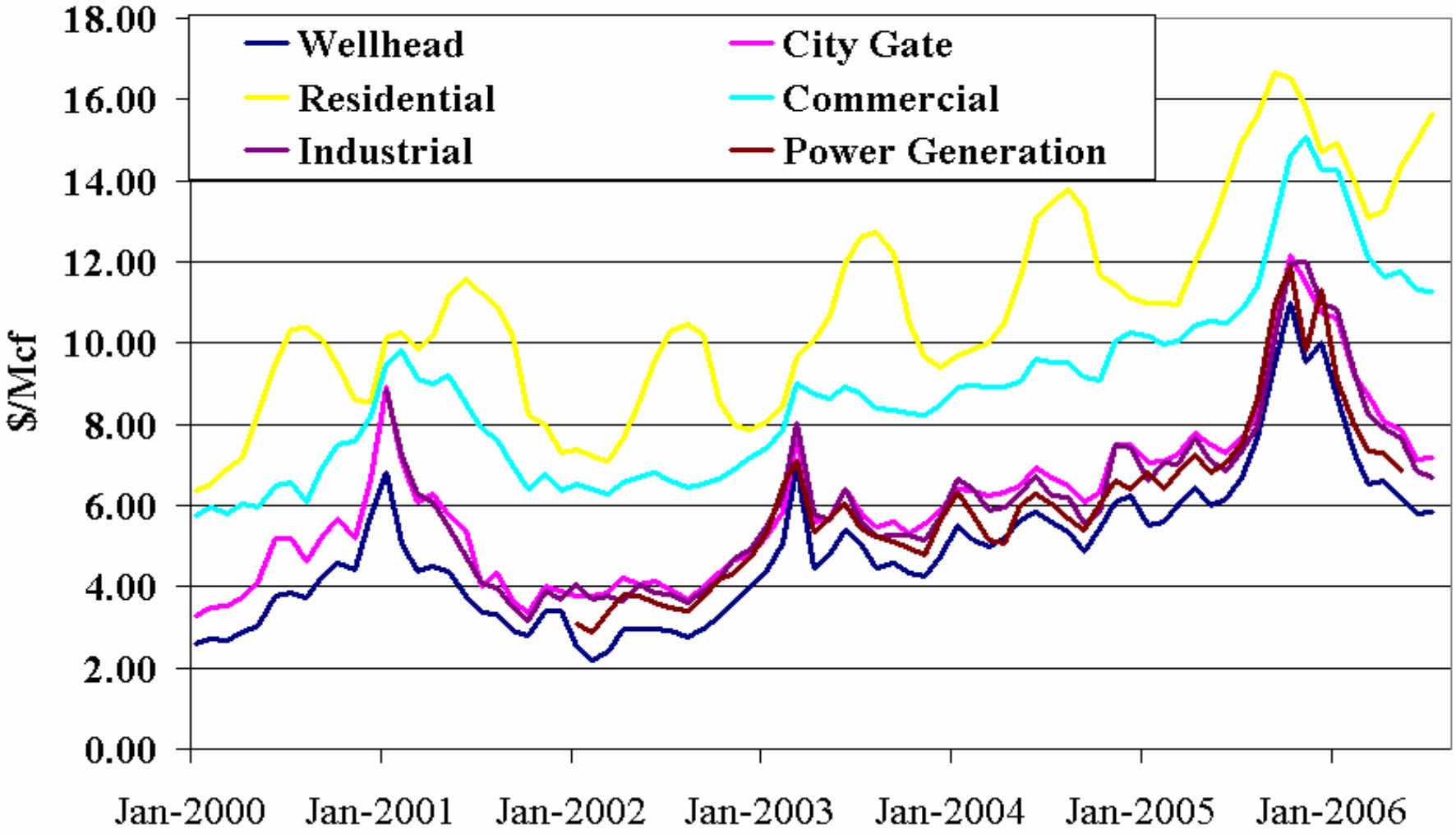
Elasticities – What and Why?

$$\varepsilon_p = \frac{\frac{\Delta Q}{Q}}{\frac{\Delta P}{P}}$$

Consumption response to prices?

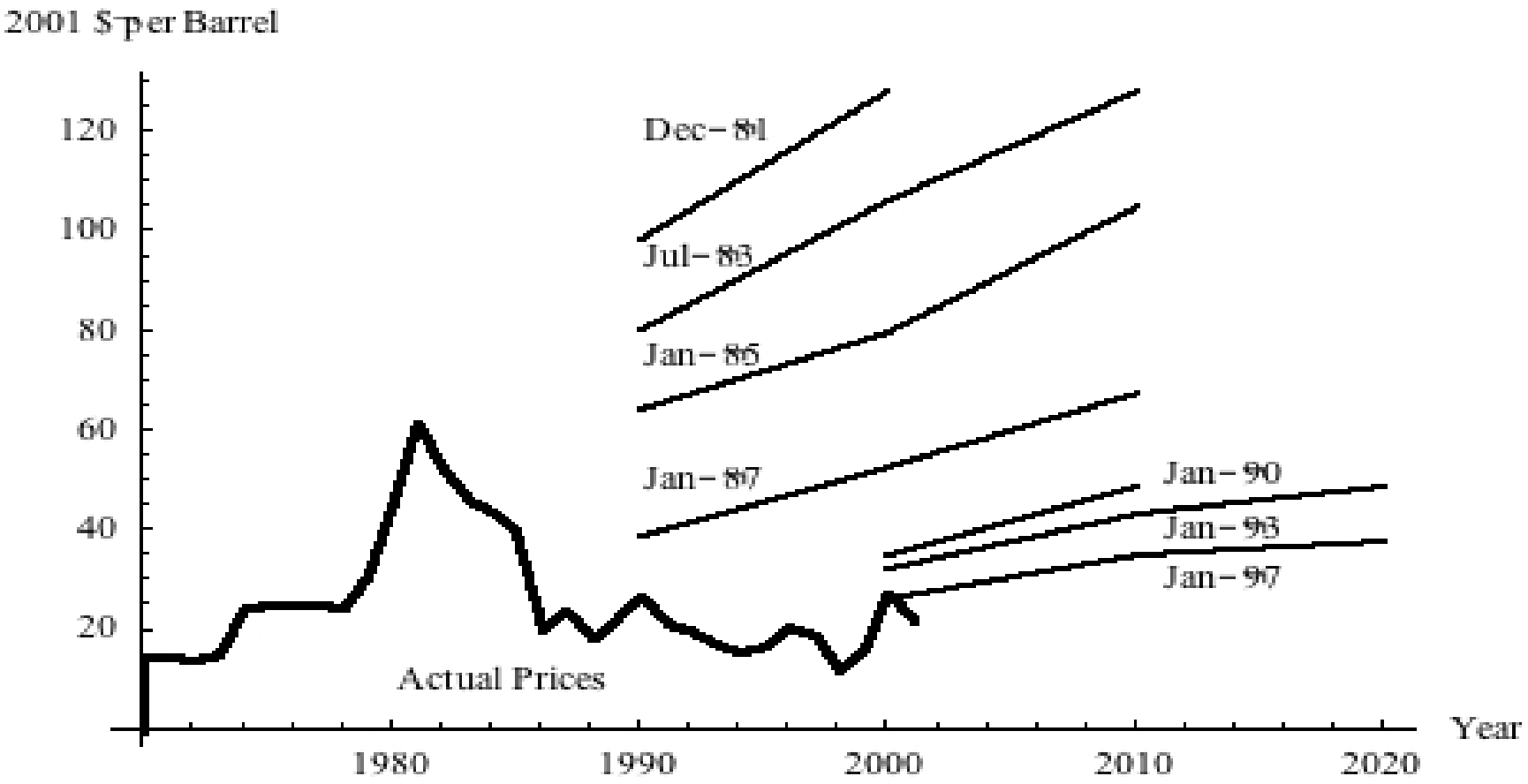


Price of Natual Gas by Sector



Can We Look into the Future

Forecasting



More Elasticities Uses?

energy taxes and subsidies

- **how much to supplier**
- **how much to consumer**
- **effects on government budgets**
- **effects on quantities**

$$\varepsilon_d = \frac{\frac{\Delta Q}{Q}}{\frac{\Delta P_d}{P_d}}$$

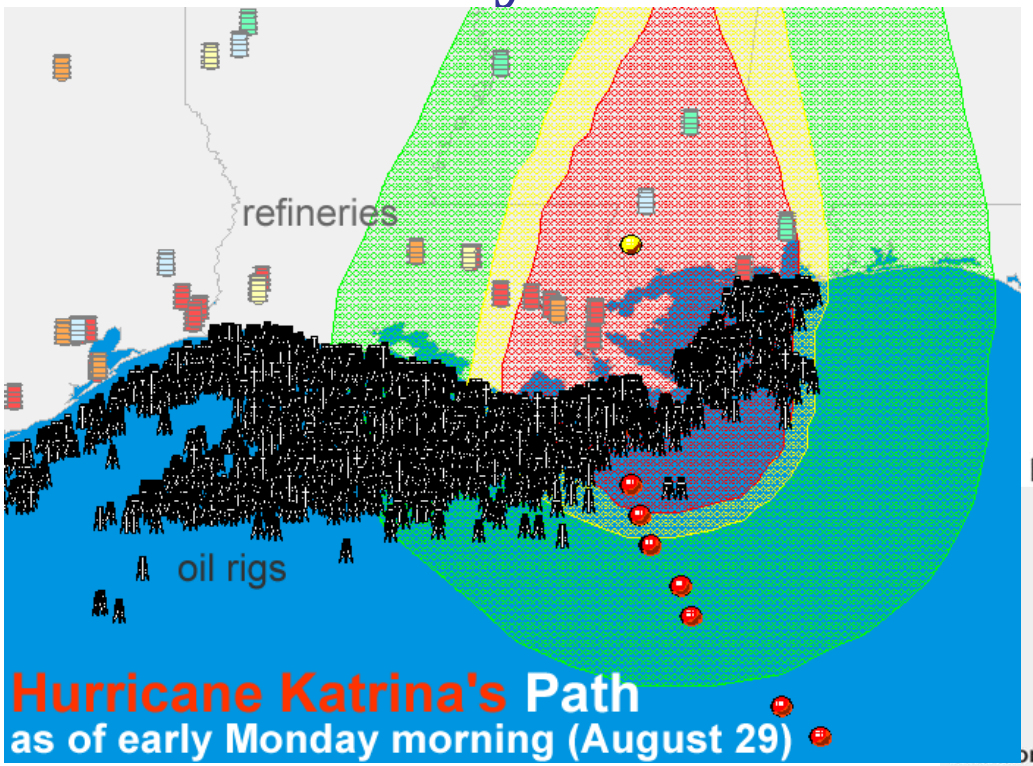
$$\varepsilon_s = \frac{\frac{\Delta Q}{Q}}{\frac{\Delta P_s}{P_s}}$$

National Petroleum Council (NPC) Natural Gas Prospects for the U.S.}

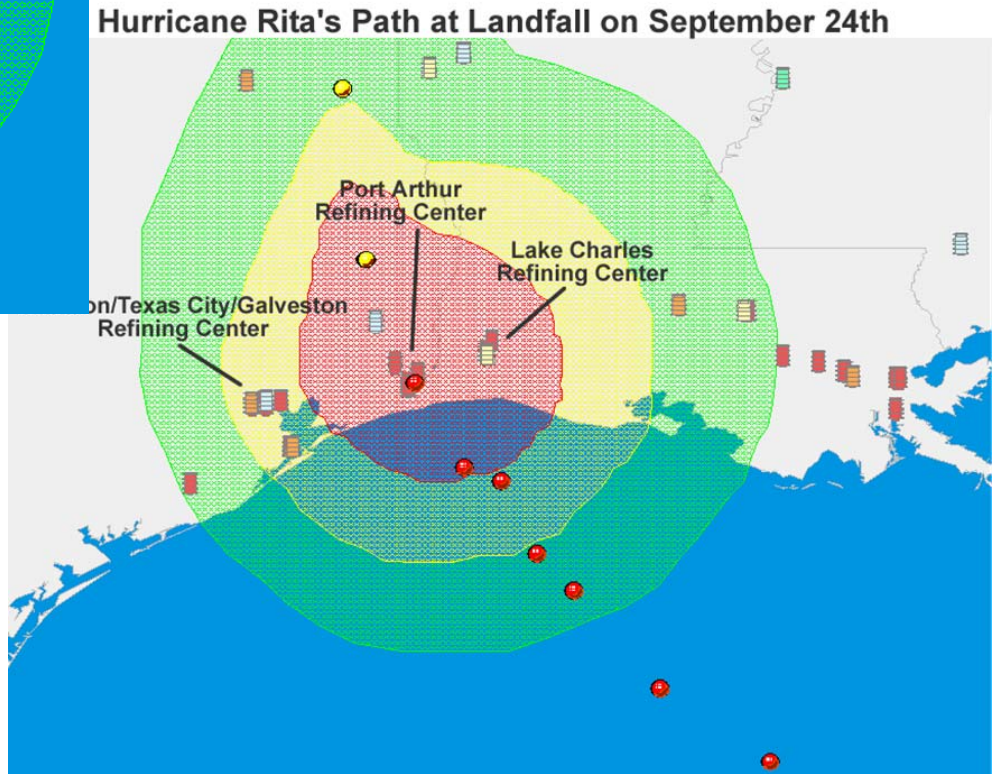
http://www.npc.org/

1. **Natural Gas Report: Volume I- Summary of Findings and Recommendations**
2. **Natural Gas Report: Volume II- Integrated Report**
3. **1999 Meeting the Challenges of the Nation's Growing Natural Gas Demand**

How Easily Can a Market React to Disruption

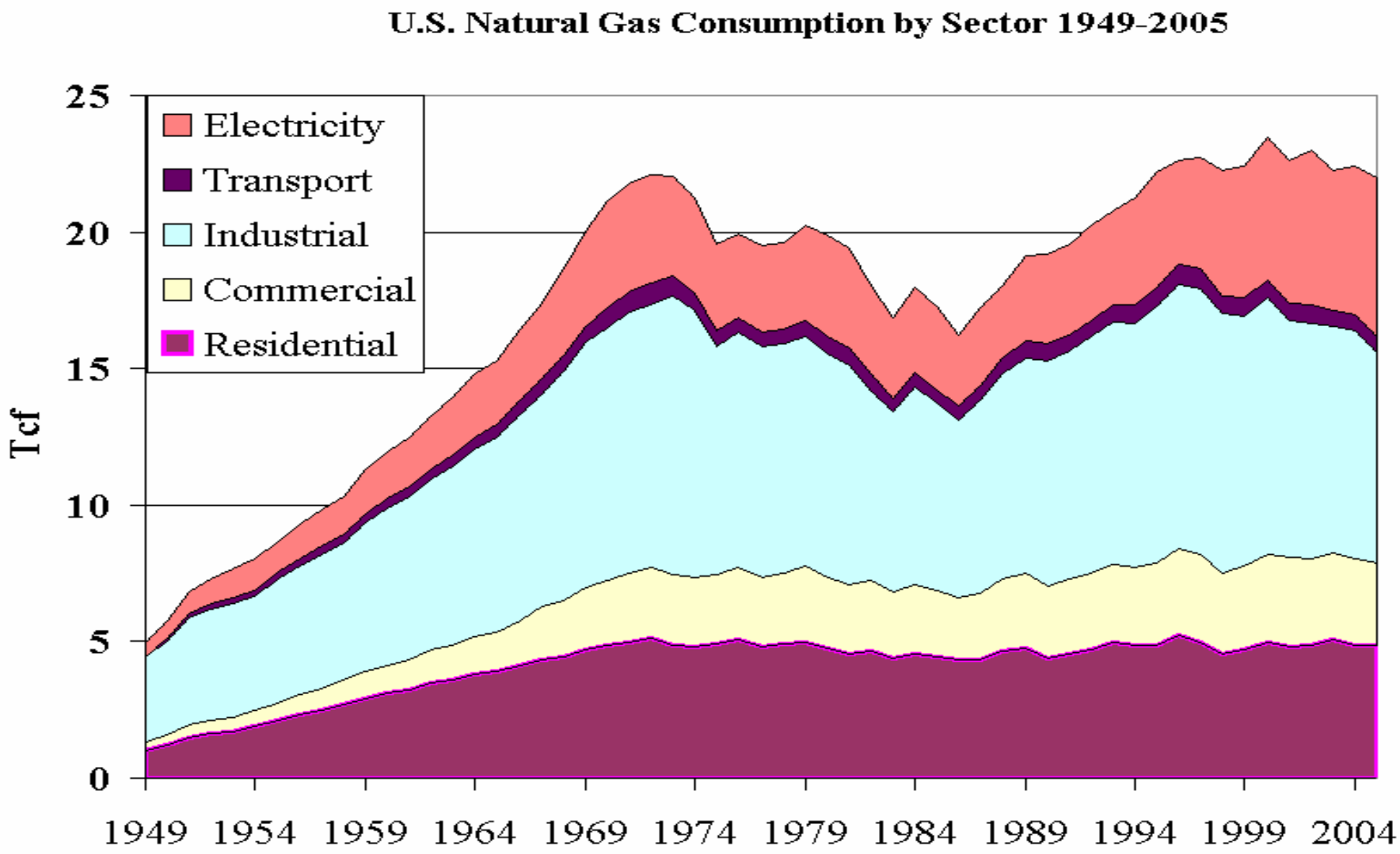


$$\frac{\Delta P}{P} = \frac{\frac{\Delta Q}{Q}}{\varepsilon_p}$$



Consumption Response to Economic Activity

$$\frac{\Delta Q}{Q} = \varepsilon_y \frac{\Delta Y}{Y}$$

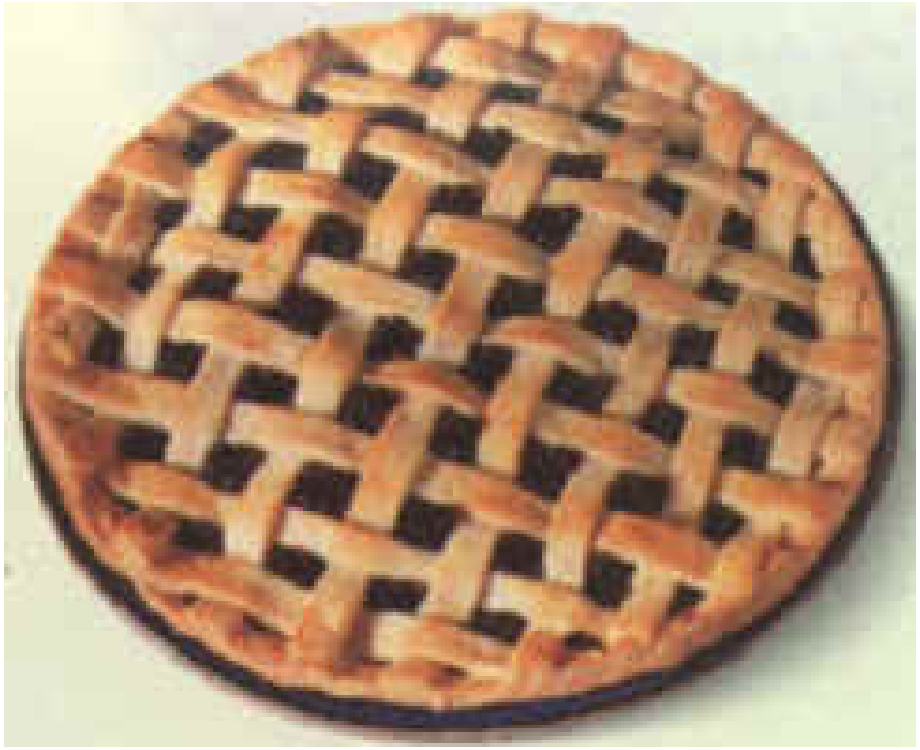


Issues in Natural Gas

Demand Destruction

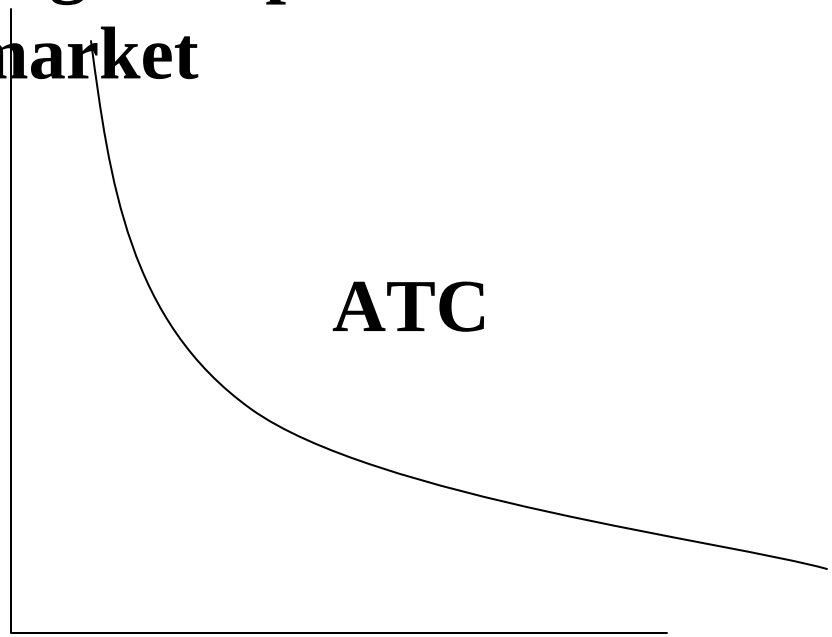
Who Gets the Pie

Where does the Pie Come From



Elasticities – What and Why?

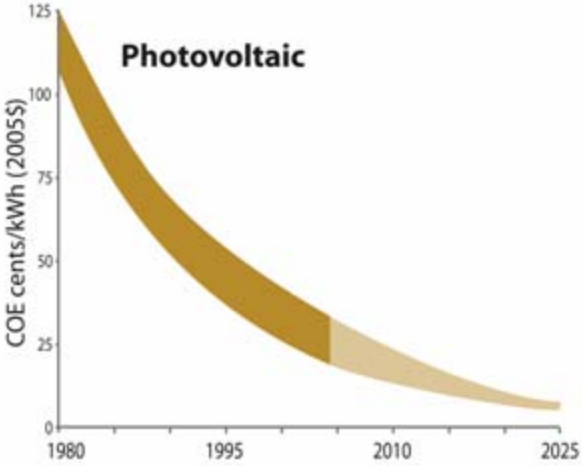
how renewable fuels might be phased into the market

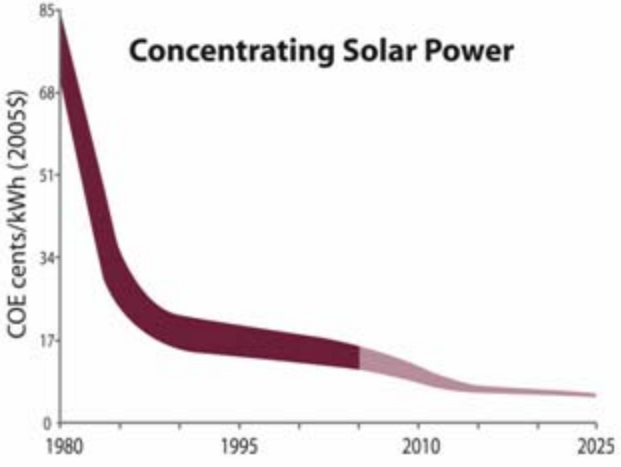


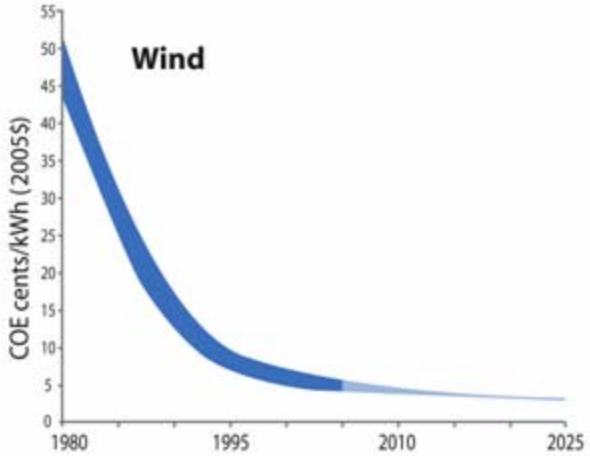
$$\varepsilon_p = \frac{\frac{\Delta Q}{Q}}{\frac{\Delta P_{sub}}{P_{sub}}}$$

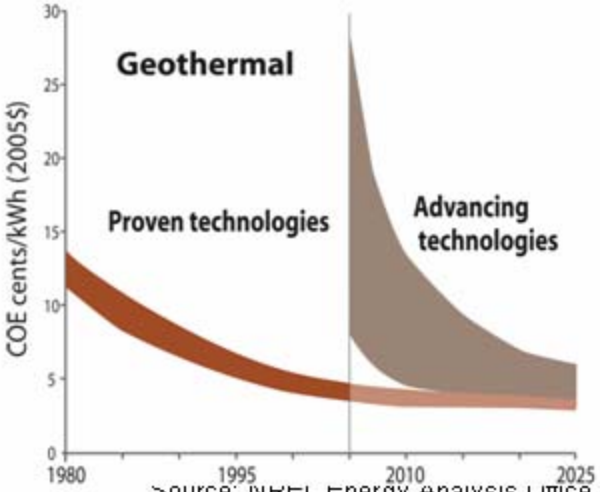
Renewable Energy Cost Trends

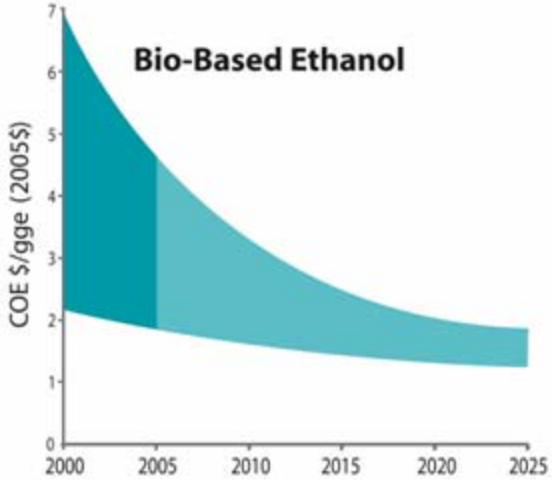
Levelized cost of energy in constant 2005$[1]











Source: NREL Energy Analysis Office (www.nrel.gov/analysis/docs/cost_curves_2005.ppt)

[1]These graphs are reflections of historical cost trends NOT precise annual historical data. DRAFT November 2005

Some issues through time

Long run versus short run

Interfactor substitution/Interfuel substitution

Aggregation Issues

- **time, commodities, individuals**

Appliance choice and use

Asymmetric response

New Methodologies

Time Series

Cubic Splines

More on household survey data

Effect of price variability on demand

Only 4 new Ng studies on U.S. since 1997

Table: Range of U.S. Energy Price and Income Elasticities				
	Price Elasticities		Income Elasticities	
	Psr	**Pir&Plr**	**Ysr**	**Yir&Ylr**
E	-0.09/-0.52	-.04/-1.75	--	.27/1.14
E-r	-0.15	-.37/-.66	1.17	.08/1.45
E-i	-0.09/-0.66	.23/-.99	--	.69/1
E-ii	0/-1.09	0/-1.10	--	0.89
El	-0.05	-.61/-1.31	--	--
El-r	0.57/-0.97	+.77/-2.2	-.02/.93	-.09/1.64
El-c	0/-.82	+3.36/-4.74	-.45/.26	-21.12/1.39
El-i	0.06/-1.03	+17.4/-3.55	.01/.28	-1.01/1.44
El-ii	-0.03/-1.51	-.11/-2.5	-.1/.82	.25/1.63

Table: Range of U.S. Energy Price and Income Elasticities				
	Price Elasticities		Income Elasticities	
	Psr	**Pir&Plr**	**Ysr**	**Yir&Ylr**
Ng	--	-.03/-.49	--	.62/.79
Ng-r	0.02/-0.88	+1.86/-3.44	.01/.44	.06/.80
Ng-c	-0.16/-0.37	1.92/-2.68	-.33/.3	-2.19/1.95
Ng-e	--	-.1/-1.89	--	--
Ng-i	-0.26/-0.63	.71/-5.28	.13/.78	.46/3.08
Ng-ii	-0.08/-1.63	-.12/-10.0	.14/1.74	.32/4.46
C-e	--	-.12/-.9	--	--
C-i	-0.02/-1.62	+.08/-1.12	--	--
C-ii	-0.84	-.28/-2.52	--	--

Table: Range of U.S. Energy Price and Income Elasticities

	Price Elasticities		Income Elasticities	
	Psr	**Pir&Plr**	**Ysr**	**Yir&Ylr**
O	-0.04/-0.25	-.25/-.94	--	0.31/1.13
O-r	-0.1/-0.59	-.62/-3.5	-.08/.21	-.28/2.28
O-c	-0.07/-0.19	-.3/-3.5	0.2	4.39
O-e	--	-.08/-3.11	--	--
O-i	-0.13/-0.21	-.08/-.44	--	--
O-ii	-0.28/-0.58	-.36/-4.05	--	--
O-ntr	.03/-.19	.1/-2.35	.03/0.38	.82/1.47
G	0/-0.36	.00/-1.99	.09/0.65	.09/1.22
J	--	-.1/-.39	--	.07/.68
O-t	0/-0.14	0/-.92	--	.63/1.1
VMT	.10/-.22	-0/-.33	-.07/.39	-0.2/1.09
MPG	.00/.01	.03/.21	--	--

New Work

Still Large Variation

Methodology

- **Simple - Static, Koyck**
- **Translog, Logit, Generalized Leontief**
- **Time Series**
  - **Engle and Granger - Nobel Prices**

Evolution of Time Series

ARMA

ARMAX

VAR

Stationarity

Cointegrated

Error Correction

Survey Strategy

Online Searchable Data Base

- **Criteria to Evaluate Studies**

Research Agenda

- **What we know**
- **What we want to know**

Checklist

I. Context
   A. The study is put into the context of the literature
II. Contribution
   A. Contribution of the paper is clearly stated
III. Methodology
   A. Correct models are used based on underlying economic theory
   B. Correctly applied econometrics and stat analysis
   C. Assumptions are tested
IV. Reproducible
   A. Clear, concise, and complete documentation of data
   B. Clear, concise and complete documentation of the methodology
   C. Clear description or clear reference for any statistical tests
V. Results
   A. Reasonable
   B. Presentation

Estimation of Elasticities

Types of Models:

Single equation (reduced form or structural):

- **Static, stock**
- **Time Series show short-run effects**
- **Cross – sections show long-run effects**
- **Stock - short run**

Estimation of Elasticities

Types of Models:

Single equation (reduced form):

- **Dynamic**
  - **lagged endogenous**
  - **other lags,**
  - **error correction models**

Estimation of Elasticities

Multi-equation systems:

- **Energy share equations**
- **Structural models**
- **Expenditure system**
- **True Simultaneous Equations**

Conclusions previous studies

Residential sector

- **Income effects consistently small**
- **for both aggregate and disaggregate data**

Commercial and industrial sectors

- **hard to measure price response**

Industrial models

- **elastic industrial demand but wide variation**

Static models suggest price-inelastic demand

Dynamic models suggest price elastic demand

		Natural Gas Total (4 studies)					
	Psr	Pir	Plr	Ysr	Yir	Ylr	Q(-1)
Mean	-0.22	-0.35	-13.32	0.02	0.71	0.94	0.98
Median	-0.22	-0.42	-13.32	0.02	0.58	0.94	0.98
StDev	0.03	0.88	6.01	0.00	0.29	0.49	0.01
Min	-0.25	-1.30	-17.57	0.01	0.46	0.60	0.98
Max	-0.20	1.46	-9.08	0.02	1.27	1.29	0.99
#	2	7	2	2	7	2	2

		Industrial (12 studies)					
	Psr	Pir	Plr	Ysr	Yir	Ylr	Q(-1)
Mean	-0.35	-0.42	-0.95	0.41	1.02	2.37	0.71
Median	-0.38	-0.52	-0.88	0.70	1.02	2.86	0.76
StDev	0.24	0.68	0.95	0.50		0.89	0.30
Min	-0.63	-2.36	-2.68	-0.29	1.02	0.93	0.03
Max	-0.01	1.20	1.92	0.96	1.02	3.12	0.90
#	12	29	33	7	1	7	7

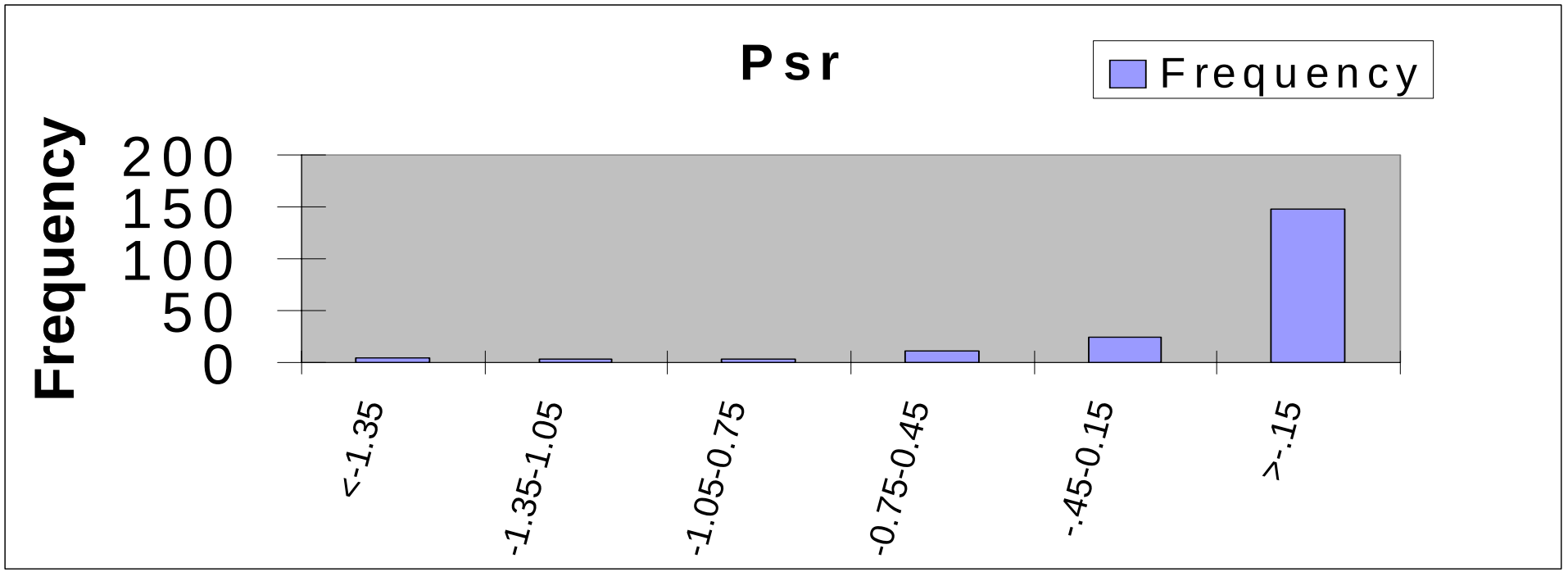
		By Industry (14 studies)					
	Psr	Pir	Plr	Ysr	Yir	Ylr	Q(-1)
Mean	-0.65	-0.93	-2.03	0.65		1.35	0.54
Median	-0.45	-0.71	-0.88	0.38		1.03	0.49
StDev	0.50	0.81	2.44	0.54		1.08	0.17
Min	-1.63	-3.81	-10.00	0.14		0.32	0.23
Max	-0.08	-0.03	-0.12	1.74		4.46	0.84
#	18	59	18	14		14	15

		Electricity Generation (15 studies)					
	Psr	Pir	Plr	Ysr	Yir	Ylr	Q(-1)
Mean	-0.45	-0.68	-0.64			0.85	
Median	-0.45	-0.33	-0.64			0.90	
StDev	0.33	0.78	0.49			0.20	
Min	-0.68	-2.55	-0.98			0.58	
Max	-0.22	0.35	-0.29			1.02	
#	2	24	2			4	

		Residential (39 studies)					
	Psr	Pir	Plr	Ysr	Yir	Ylr	Q(-1)
Mean	-0.17	-0.77	-0.47	0.24	0.14	0.09	0.53
Median	-0.13	-0.68	-0.24	0.12	0.15	0.13	0.50
StDev	0.31	0.78	0.85	0.46	1.32	0.86	0.26
Min	-2.17	-7.14	-5.28	-0.75	-16.04	-5.13	0.02
Max	1.07	1.35	2.20	2.73	1.55	2.19	0.99
#	128	248	145	52	181	50	51

		Residential and Commercial (8 studies)					
	Psr	Pir	Plr	Ysr	Yir	Ylr	Q(-1)
Mean	-0.26	-0.52	-1.16	0.08	1.74	0.53	0.97
Median	-0.15	-0.10	-1.01	0.08	1.35	0.52	0.97
StDev	0.22	2.17	0.76		2.20	0.09	0.02
Min	-0.58	-12.89	-2.67	0.08	-2.94	0.44	0.95
Max	-0.15	2.78	-0.62	0.08	9.76	0.62	0.98
#	4	80	6	1	74	3	2

		Commercial (10 studies)					
	Psr	Pir	Plr	Ysr	Yir	Ylr	Q(-1)
Mean	-0.26	-0.51	-0.71	0.24	0.42	0.34	0.75
Median	-0.22	-0.38	-0.78	0.11	0.46	0.59	0.82
StDev	0.13	0.52	0.95	0.47	0.28	1.19	0.24
Min	-0.57	-1.62	-2.41	-0.33	0.13	-2.19	0.10
Max	-0.08	-0.03	1.86	1.03	0.68	1.95	0.85
#	11	8	30	9	3	9	9


Psr
Frequency
Frequency
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100
50
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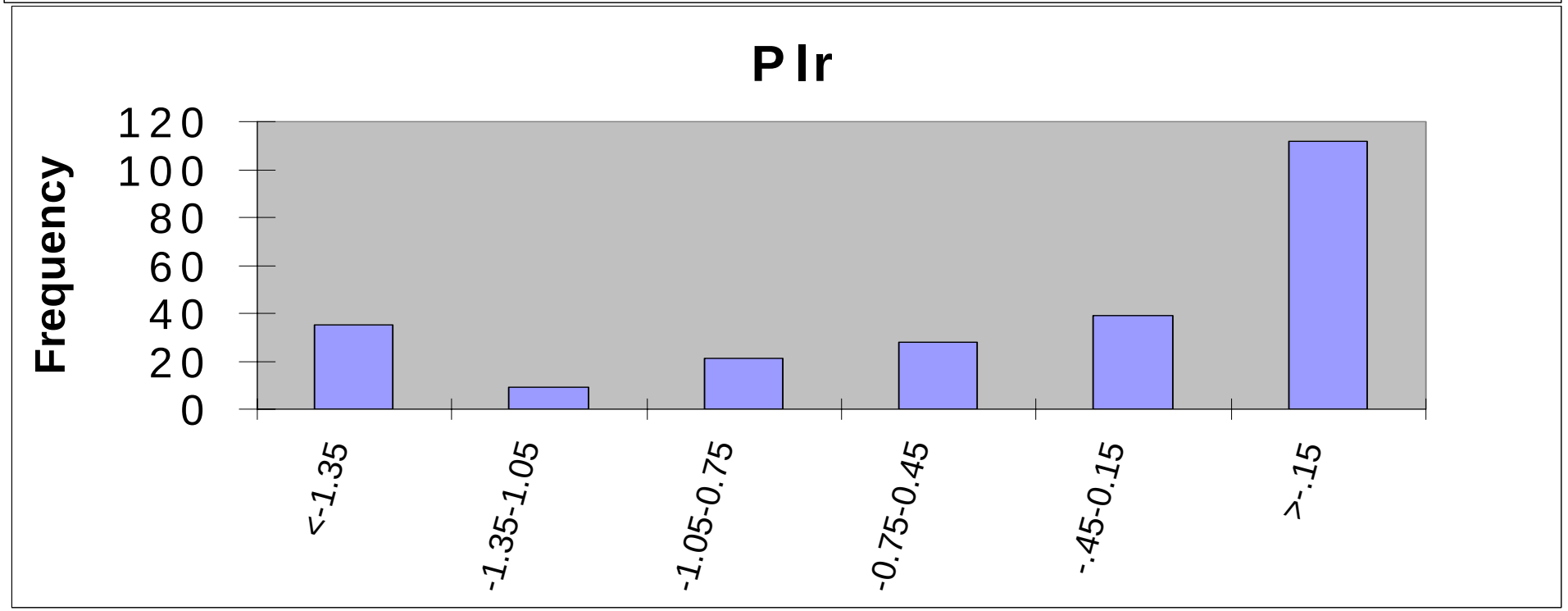
-1.35-1.05
-1.05-0.75
-0.75-0.45
-.45-0.15
>-.15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80
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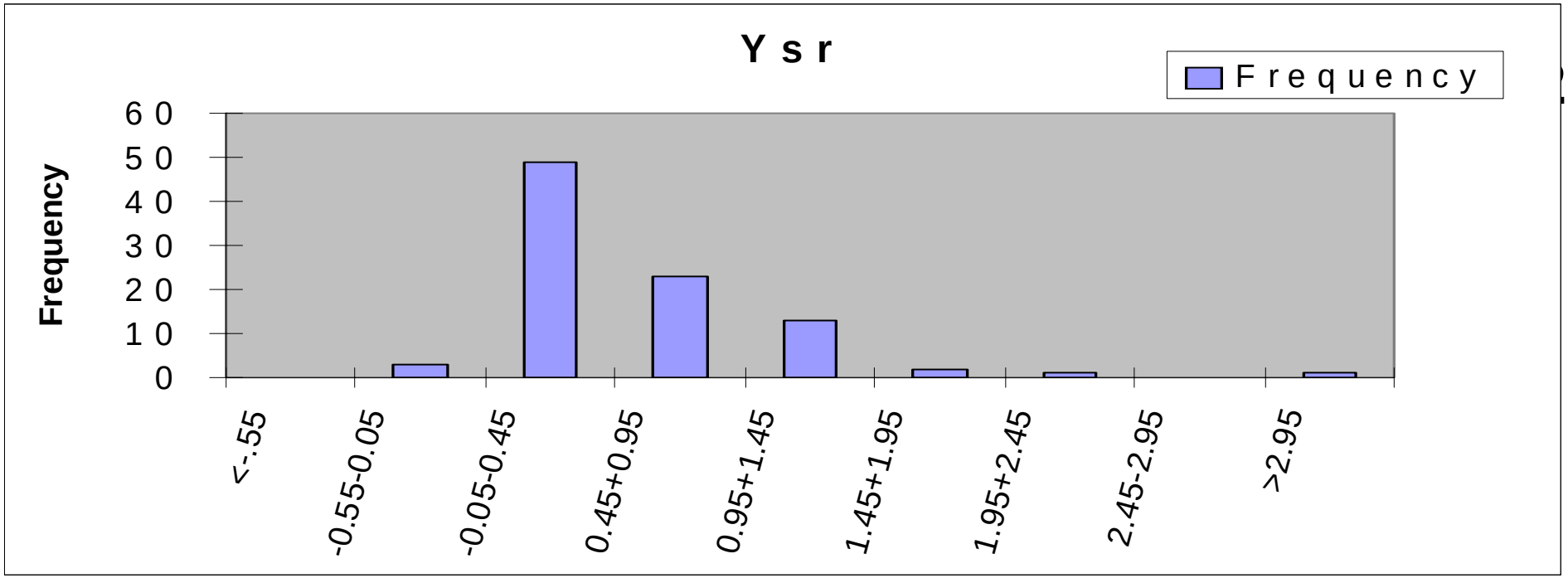
-.45-0.15
>-.15


Y s r
Frequency
Frequency
60
50
40
30
20
10
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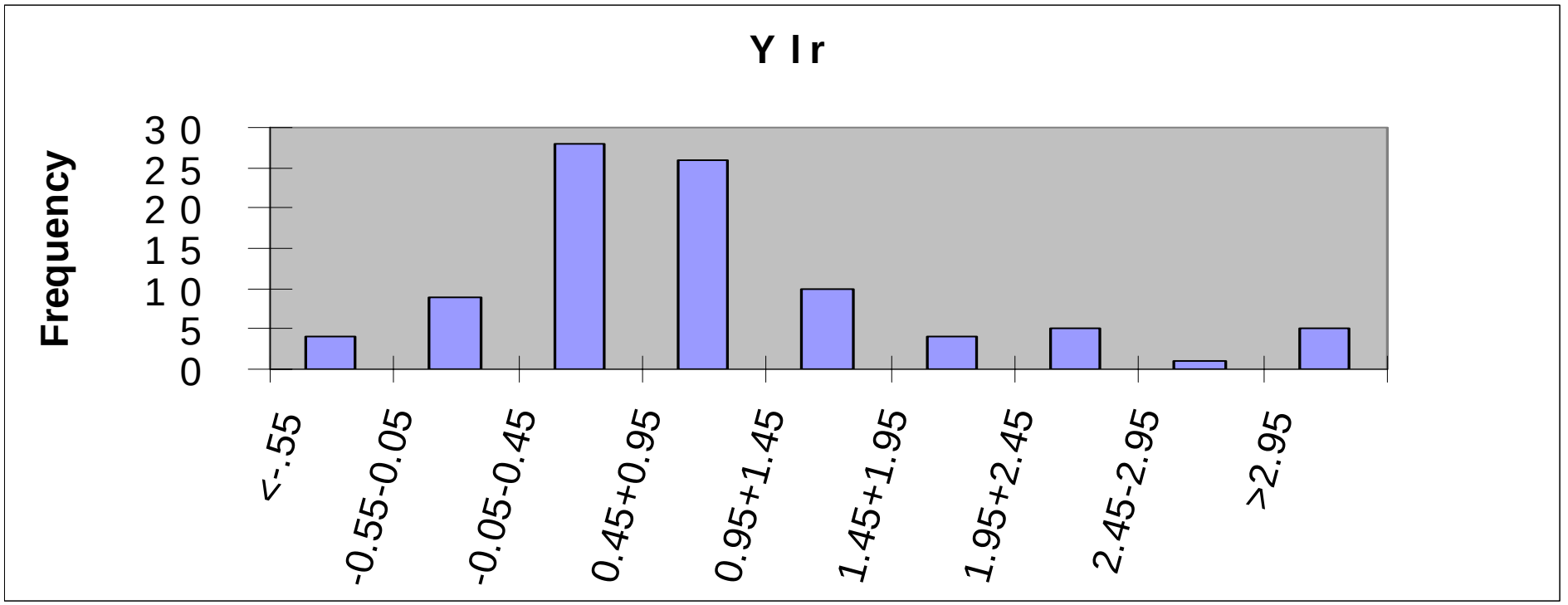
<-.55
-0.55-0.05
-0.05-0.45
0.45+0.95
0.95+1.45
1.45+1.95
1.95+2.45
2.45-2.95
>2.95


Y I r
Frequency
30
25
20
15
10
5
0
<-.55
-0.55-0.05
-0.05-0.45
0.45+0.95
0.95+1.45
1.45+1.95
1.95+2.45
2.45-2.95
>2.95

Meta-Analysis

Regress elasticity on

-r, -i, -ii, -e, c, r&c

T, CT, C

Stat, Dynamic

m & Q

<1974, 74-90, 90-99, >99

Non-US

Pcross

Meta-analysis – Psr ($R^2 = 0.4$)

Results Poor Non-US – used only US data

-ii more elastic

<74 and 90-99 less elastic

C more elastic

-h more elastic

Pcross – less elastic

OL- less elastic

Meta-analysis – Plr ($R^2 = 0.51$)

-ii more elastic

<74 less elastic

C more elastic CT more elastic T

-h less elastic

Pcross – less elastic

Meta-analysis – Y

Ysr (R^2 = 0.30)

m&q – less elastic

Ylr (R^2 = 0.33)

-i and –ii more elastic

<74 less elastic

m&q less elastic

Pcross more elastic

Forecasting short-run USA natural gas demand

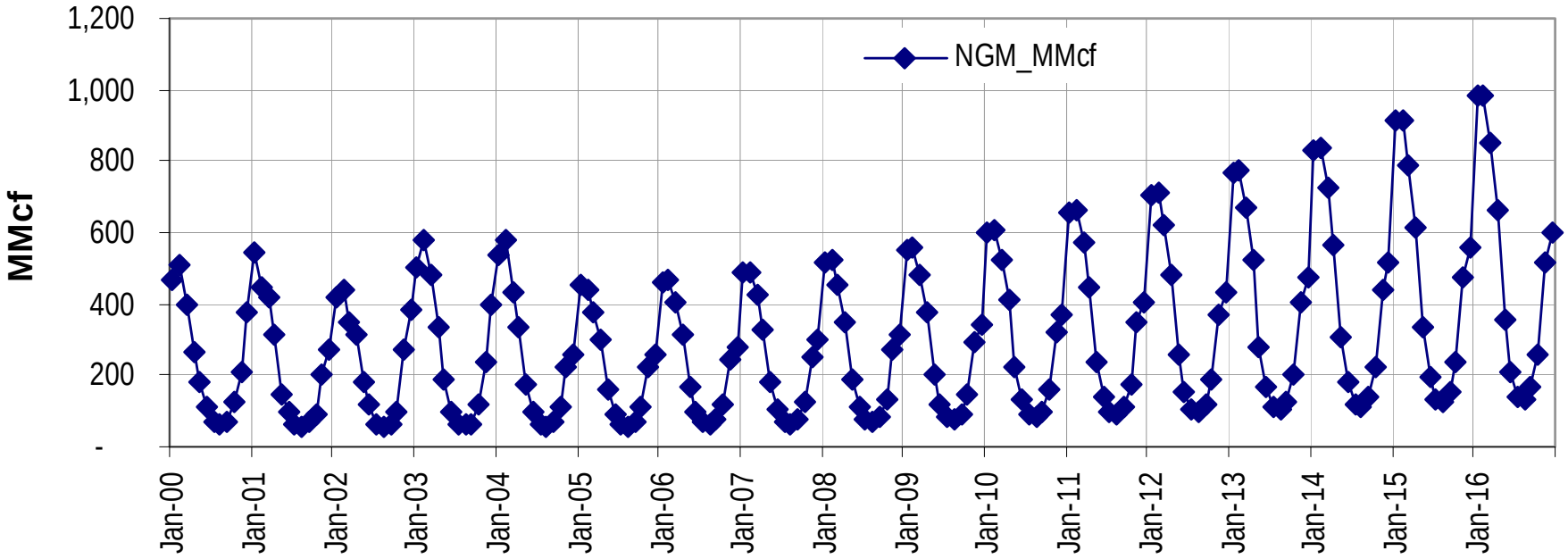
Residential and commercial sectors:

$$Q = \beta_0 + \beta_1 Pg_{t-1} + \beta_2 Pel_{t-1} + \beta_3 Y_t + \beta_4 HDD_t + \beta_5 CDD_t + \beta_6 Q_{t-1} + Month + e_t$$

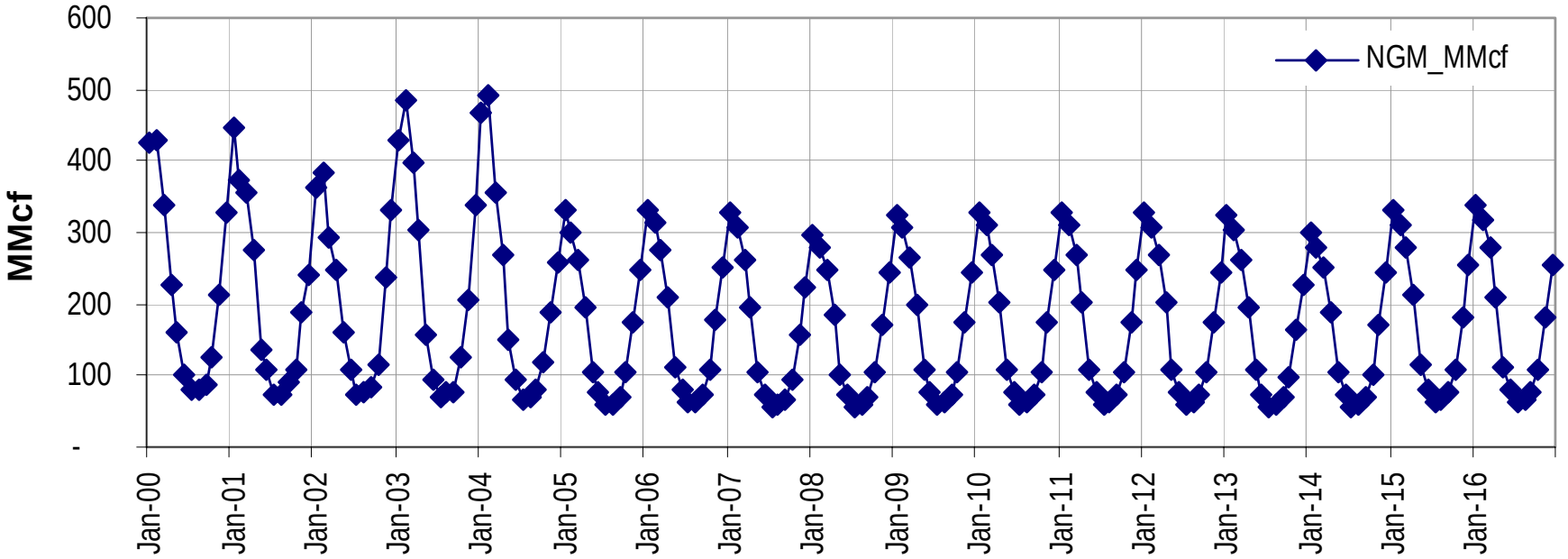
Monthly data:

- **Strong seasonal effects**
- **Not significant income, price, weather effects**

Forecast Vermont, residential sector



Forecast Vermont, commercial sector



Conclusions

Seasonal effects dominate estimated parameters

Monthly data may not capture price adjustments

Most weather effects picked by seasonal dummies

Impressions so Far

Currently lots of work being conducted

Still see quite a lot of variability

Gasoline and household still seem more stable

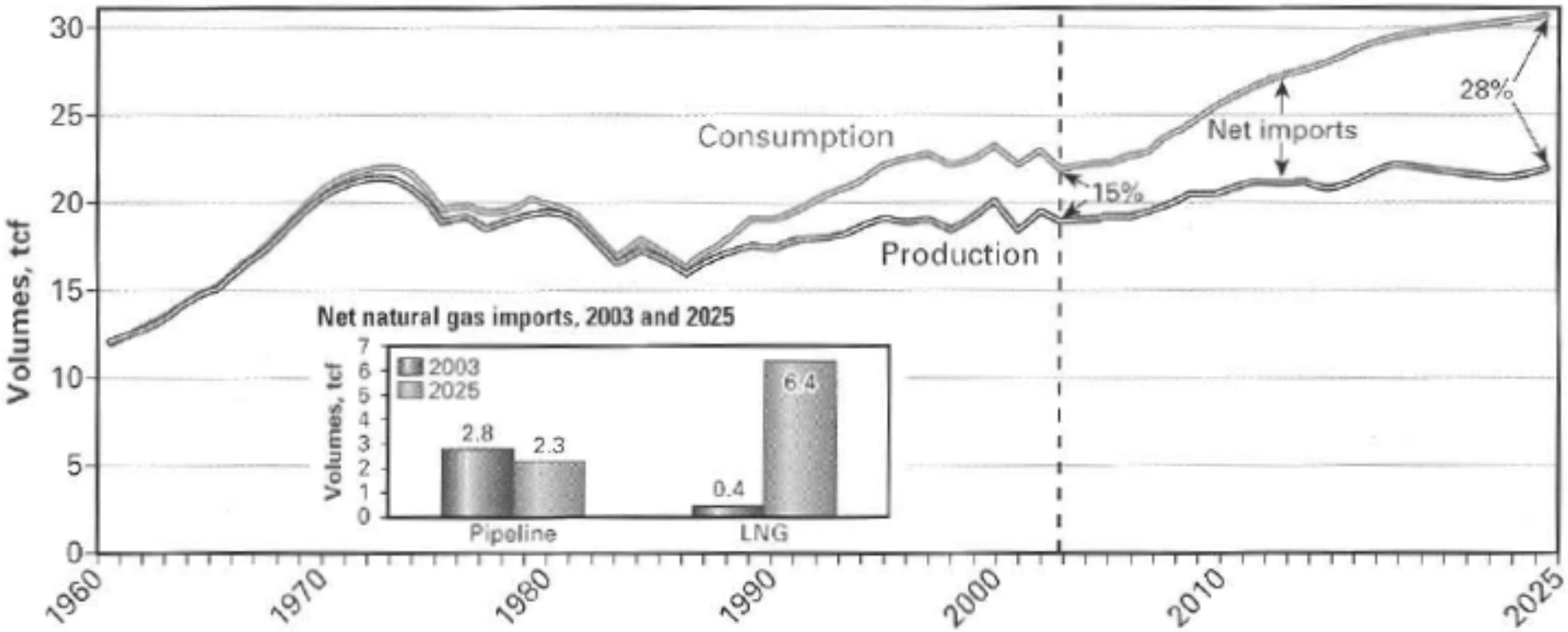
Long run eludes us

Lots of time series studies

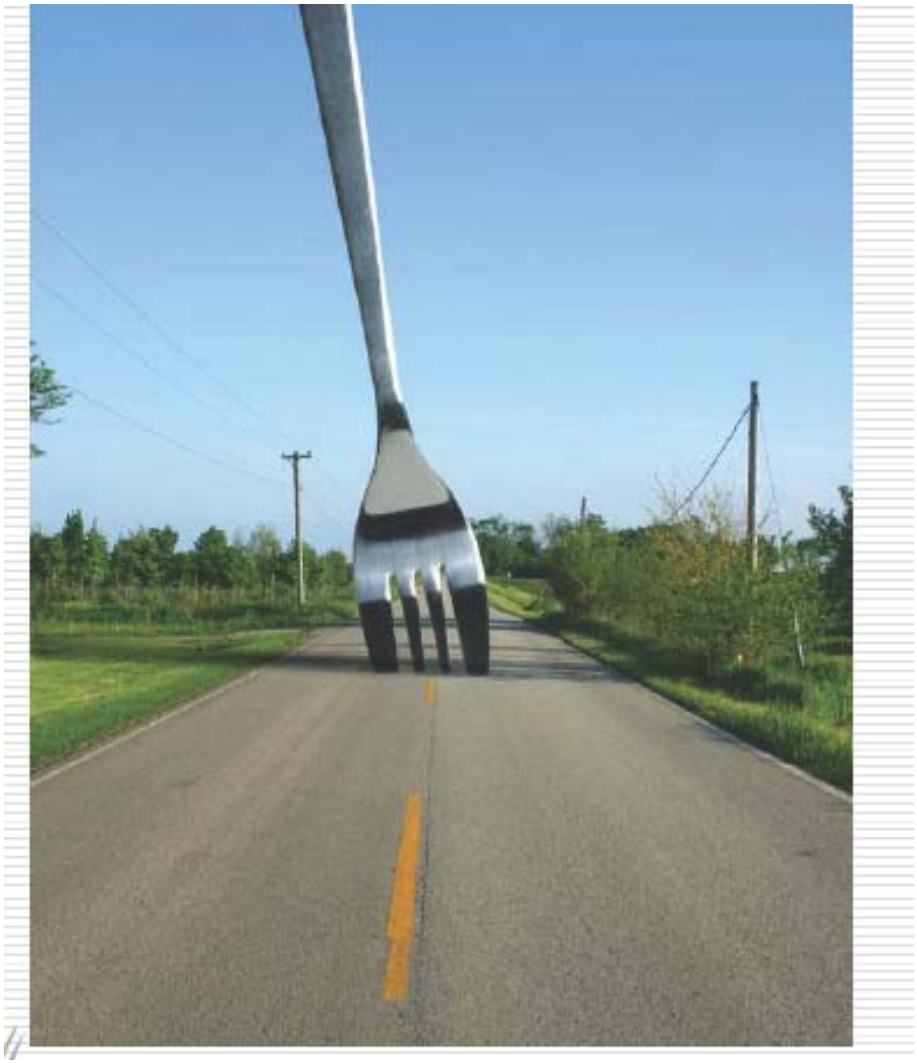
Quite a few household panel studies

US NATURAL GAS PRODUCTION, CONSUMPTION, IMPORTS

Fig. 1



Source: EIA Annual Energy Outlook 2005



Where will the Gas Come From?

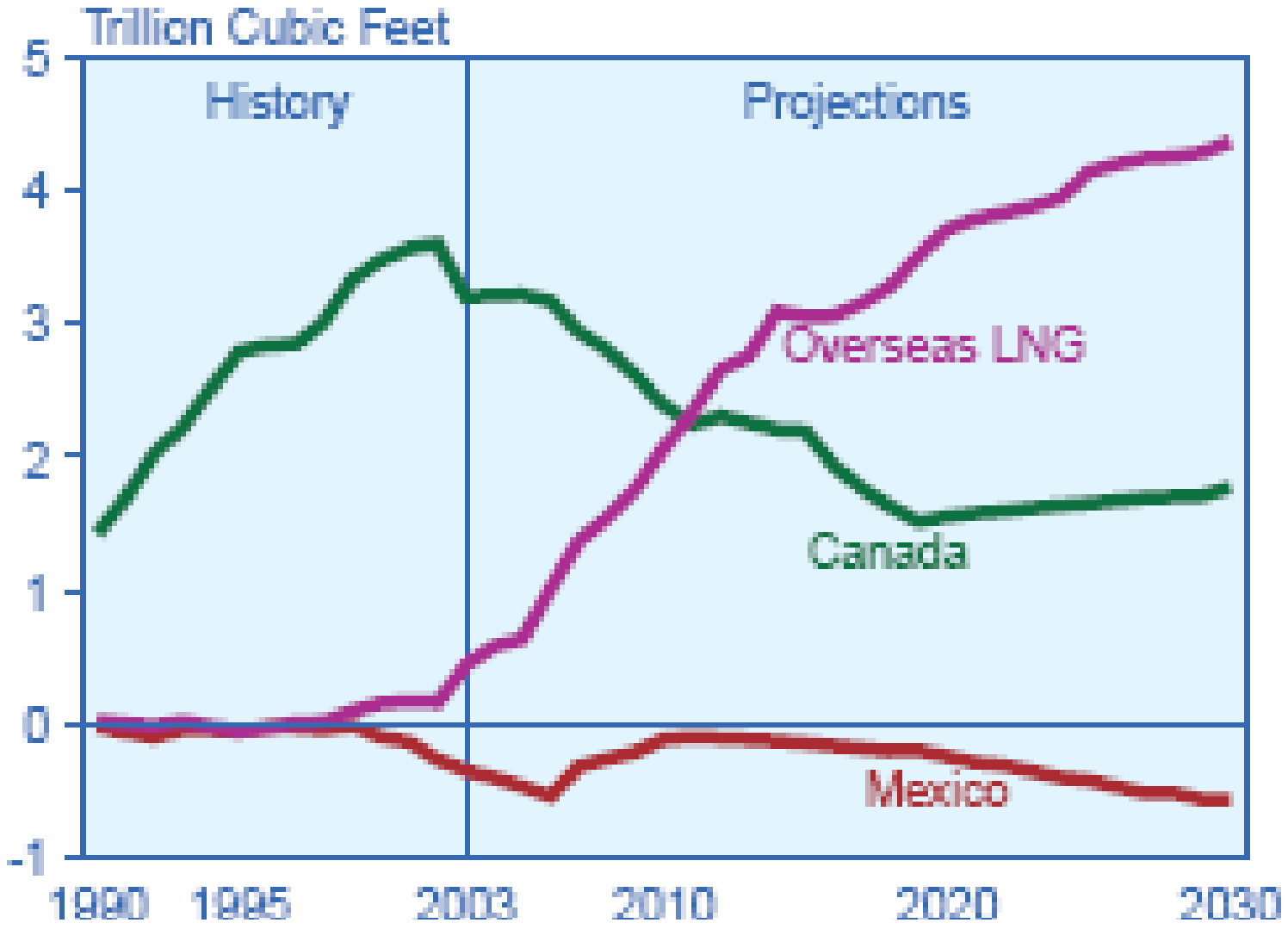
The decrease of LNG costs (technical progress & economies of scale)

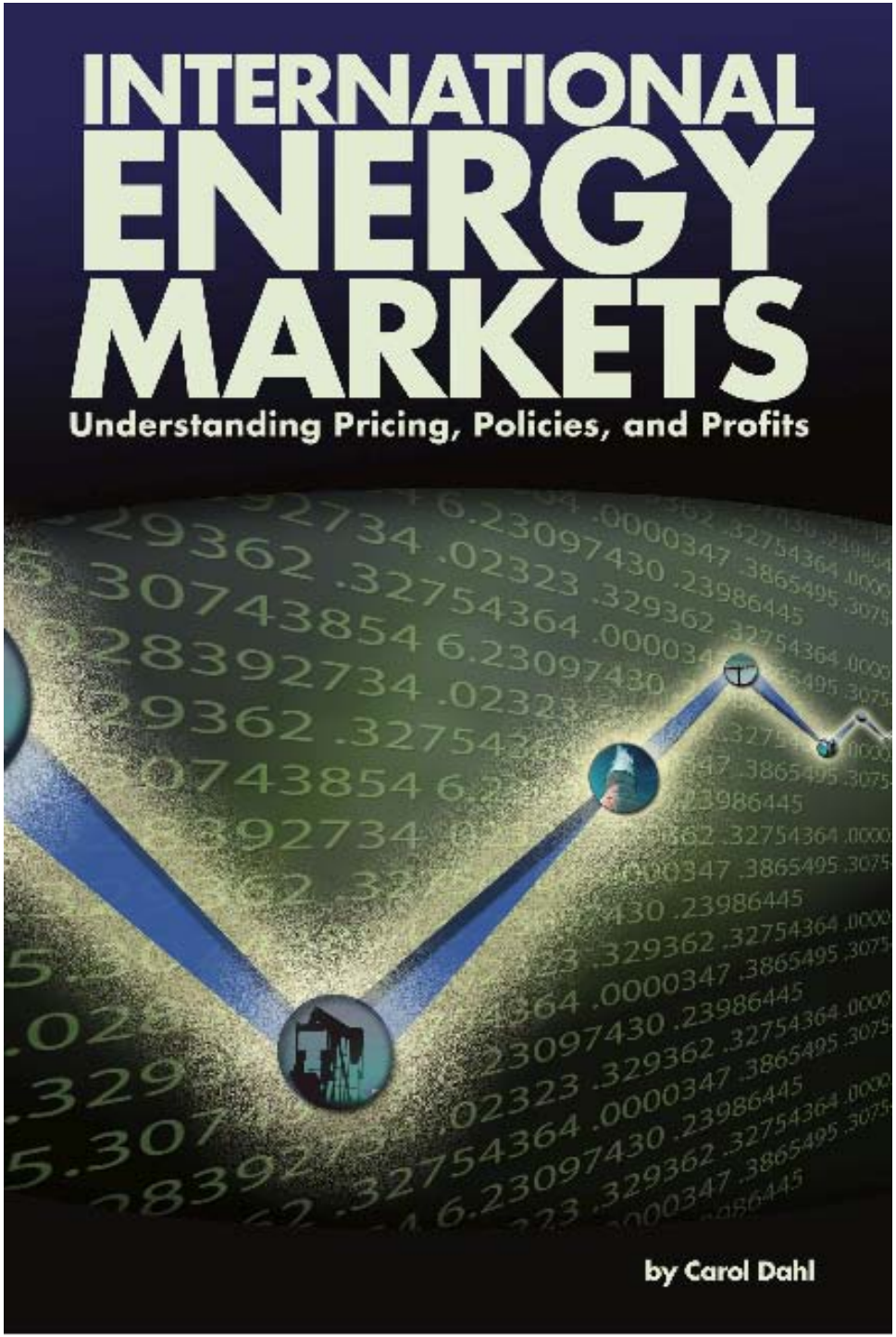
Cost of LNG

USD/Mbtu	Cost estimate early 1990s	Cost estimate early 2000s
Upstream development costs	0.5 – 0.8	0.5 – 0.8
Liquefaction	1.3 – 1.4	1.0 – 1.1
Shipping (LNG tankers)	1.2 – 1.3	0.9 – 1.0
Regasification	0.5 – 0.6	0.4 – 0.5
Total cost	**3.5 – 4.1**	**2.8 – 3.4**

Source: Cedigaz (2003)

Figure 41. U.S. Natural Gas Supply by Source, 1990-2030




INTERNATIONAL
ENERGY
MARKETS
Understanding Pricing, Policies, and Profits
by Carol Dahl

amazon.com

Attachment 5.4

SOURCE: 2004 ANNUAL REVIEW

4.0 COST PROJECTIONS FOR REGULAR CAPITAL AND CPCN'S

4.1 Cost Projections for Regular Capital

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

Cost Projections for Regular Capital Expenditure 2005-2009

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

Note: All estimates exclude AFUDC

4.2 Cost Projections for CPCN's

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

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

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

Note: All estimates exclude AFUDC

SOURCE: 2005 ANNUAL REVIEW

In the first scenario (Scenario A below), longer term commodity drop and customer capture rates for the period are consistent with levels currently experienced, with some modest increases reflecting sales and marketing efforts.

In the second scenario, it is assumed that commodity prices are sustained at the current high levels with the result that customer capture rates will be eroded. Accordingly, Terasen Gas has prepared this alternative forecast of customer additions and capital expenditures (Scenario B below) that reflects a reduction in the number of customers captured of approximately 25%. The modest increases in customer capture over the forecast period related to the sales and marketing strategies described above are included in this scenario.

SCENARIO A

Cost Projections for Regular Capital Expenditure 2006-2010 - Challenge Targets

Forecasted Customer Additions - Challenge Targets	12,718	12,276	12,903	13,575	14,043
Customer Driven Capital	**2006**	**2007**	**2008**	**2009**	**2010**
Mains	6,611	6,573	7,116	7,711	8,216
Services	12,143	12,073	13,070	14,163	15,091
Meters - Customer Additions	3,913	3,890	4,212	4,564	4,863
	22,667	**22,536**	**24,398**	**26,438**	**28,170**
Other Regular Capital	**2006**	**2007**	**2008**	**2009**	**2010**
Meters - Replacement	12,292	12,865	15,983	16,792	17,659
System Integrity & Reliability					
Transmission Plant	6,363	5,932	5,145	4,841	5,063
Distribution Plant	16,921	8,999	9,449	7,793	7,949
Other Regular Capital					
Non - IT	11,692	11,946	12,222	12,466	12,716
IT	10,500	13,500	11,400	11,700	11,900
	57,768	**53,242**	**54,199**	**53,592**	**55,287**
Total Regular Capital	**80,435**	**75,778**	**78,597**	**80,030**	**83,457**

Note: All estimates exclude AFUDC

Capital Additions "Customer Driven" Capital

- Mains
- Services
- Meters for New Customer Additions

Other Regular Capital

- Meter Replacements
- Transmission Plant
- Distribution Plant
- IT Capital
- Non-IT Capital

Table 1 includes a comparison of the 2006 Budget versus Projection for 2006 as well as capital expenditure forecasts for the period 2007 to 2011.

Table 1 - Forecast of Regular Capital Expenditure Targets (2006 - 2011)

	2006 Budget	2006 Projection	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast
Forecasted Year End Customer Additions	12,718	12,755	13,160	12,399	12,633	13,285	14,276
Customer Driven Capital							
Mains	6,611	6,964	7,728	7,428	7,722	8,285	9,083
Services	12,143	14,247	15,552	15,005	15,655	16,858	18,550
Meters (Customer Additions)	3,913	4,324	4,172	4,048	4,249	4,602	5,093
	22,667	**25,536**	**27,452**	**26,481**	**27,625**	**29,744**	**32,727**
Other Regular Capital							
Meters - Replacement	12,292	11,404	12,327	19,063	19,976	20,933	21,936
Transmission Plant	6,363	10,037	6,401	11,652	4,841	5,063	5,164
Distribution Plant	16,921	10,555	8,806	9,184	7,793	7,949	8,108
IT	10,500	9,920	12,742	10,736	11,038	11,246	11,471
Non-IT	11,692	13,640	11,946	12,222	12,466	12,716	12,970
	57,767	**55,556**	**52,222**	**62,857**	**56,113**	**57,906**	**59,649**
Total Regular Capital	**80,435**	**81,092**	**79,673**	**89,339**	**83,739**	**87,650**	**92,376**

Figures exclude AFUDC and Capitalized Overheads.

1.2 Revisions to the 2006 & 2007 forecast since the 2005 Annual Review

Terasen Gas is aware that the figures provided for 2006 and subsequent years differ from those presented in the 2005 Annual Review. For the convenience of readers, a high level explanation of how costs differ from the 2005 Annual Review Major Capital Plan - Scenario A, ("2005 Five Year Capital Plan") is provided below for the remaining years of the current PBR (2006 and 2007). The comparison to Scenario A, as opposed to Scenario B has been used because Scenario A was based upon the assumption that the long-term commodity price growth pattern would follow a growth rate roughly corresponding with the three year period leading up to Autumn 2005 at which point supply shortfalls caused the natural gas commodity price to significantly increase.

Capital Additions "Customer Driven" Capital

- Mains
- Services
- Meters for New Customer Additions

Other Regular Capital

- Meter Replacements
- Transmission Plant
- Distribution Plant
- IT Capital
- Non-IT Capital

Table 1 includes a comparison of the 2007 Forecast versus Projection for 2007 as well as capital expenditure forecasts for the period 2008 to 2012.

Table 1 - Forecast of Regular Capital Expenditure Targets (2007 - 2012)

	2007 Forecast	2007 Projection	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast	2012 Forecast
Forecasted Year End Customer Additions	13,160	13,129	11,797	11,346	11,148	11,047	11,048
Customer Driven Capital							
Mains	7,728	8,972	9,527	9,437	9,551	9,749	10,043
Services	15,552	17,871	19,443	19,260	19,492	19,896	20,496
Meters (Customer Additions)	4,172	4,140	3,834	3,798	3,844	3,924	4,042
	27,452	**30,983**	**32,804**	**32,496**	**32,888**	**33,569**	**34,581**
Other Regular Capital							
Replacement Customer Meters (Allocation)	12,327	11,089	13,392	17,231	21,082	25,414	27,310
Transmission Plant	6,401	4,912	11,652	4,841	5,063	5,164	5,267
Distribution Plant	8,806	10,224	9,174	7,793	7,814	8,058	8,270
IT	12,742	5,255	10,736	11,038	11,246	11,471	11,471
Non-IT	11,946	12,036	12,301	12,450	12,699	12,953	13,212
	52,222	**43,517**	**57,255**	**53,352**	**57,904**	**63,060**	**65,530**
Total Regular Capital	**79,674**	**74,500**	**90,059**	**85,848**	**90,791**	**96,629**	**100,111**

Figures exclude AFUDC and Capitalized Overheads.

1.2 Comparison of 2007 Forecast vs. 2007 Projection

When compared with the figures presented in the 2006 Five Year Capital Plan, Total Regular Capital, the year-end forecast for 2007 is lower by 6.5%. Below is an explanation of the primary driver(s) of forecast differences.

Current net customer addition forecasts for Terasen Gas can be found in Table 1 above. When compared with the forecasts presented in the 2006 Five Year Capital Plan, Customer Driven Capital is forecast to be approximately $3.5 million higher for 2007. These increases are