# Declining Average Customer Use of Natural Gas: Issues and Options

# Declining Average Use per Customer: Issues and Options for Canada's Natural Gas Distribution Utilities

This document was prepared for Canadian Gas Association by IndEco Strategic Consulting Inc.

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IndEco report A6336

18 December 2006

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# Executive summary

Natural gas utilities across Canada are experiencing declining gas usage per customer. For some utilities the decline is across all sectors; for others the decline is centred on residential and on small commercial and small industrial customers. This decline has been happening in the market over time due to energy efficiency improvements in new construction and the turnover in stock to higher efficiency gas furnaces. The decline has gained greater notice in recent years because high and volatile gas prices are moving consumers to further reduce gas use. These prices are creating increased pressure on the utilities from governments and stakeholders to place greater emphasis on energy efficient gas use through the delivery of demand-side management (DSM) services to customers. In addition, there are specific factors pertinent to particular franchise areas that are magnifying the decline.

From a customer perspective, decline in average use is very positive; it means that customers are using natural gas more wisely and are saving money on their gas bills. From a utility perspective, decline in use per account has a positive benefit because this contributes to customer retention. For utilities with DSM, their DSM programs further help their customers to achieve wise gas use and savings on gas bills. However, if declines in average use are not properly addressed through effective rate regulation, this could jeopardize the continued effectiveness of gas DSM, discourage utilities from promoting wise gas use and result in significant lost earnings for the utility.

The Canadian Gas Association retained IndEco Strategic Consulting Inc. in June 2006 to explore at a high level the nature and extent of the decline in gas usage across Canadian natural gas utilities, to identify implications of this decline and to assess options for managing its negative consequences on the gas utilities. This paper documents the research and findings of this work.

## Methodology

Ten natural gas utilities across Canada participated in this study. They are: AltaGas, ATCO Gas, Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, Pacific Northern Gas (PNG) SaskEnergy, Terasen Gas and Union Gas. Each utility was asked to provide data from which to analyze actual declines in average use. Enbridge Gas New Brunswick and Heritage Gas in Nova Scotia were excluded from the study as these utilities are relatively new and are focused on adding customers to the distribution system.

In addition to obtaining data from the utilities relevant to analyzing declining average use, IndEco conducted telephone interviews in July and August 2006 with Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, Terasen Gas and Union Gas, and in October 2006 with PNG and AltaGas to supplement the data analysis.

## Findings and recommendations

A major finding of this work is that Canadian natural gas utilities have been experiencing a steady trend of declining natural gas use per customer. Analysis of actual use data, provided by the utilities over this period, and normalized by number of customers and weather, shows a decline in average use of natural gas across all sectors of 19% over the past 13 to 15 years, while across the residential sector, that decline has been 16%. This corresponds roughly to a decline in average use of 1.9% per year for all sectors and to a decline in average use in the residential sector specifically, of 1.1% per year.

The analysis of the Canadian situation has revealed that changes in number of customers and climatic variation are not the main drivers of declining average use. As numbers of customers have continually increased and climatic temperature variation has been shown to have, in general, a very minor effect on natural gas use change, other factors must be driving the decline.

### Contributing factors to declining average use in Canada

Over time Canadian homes and businesses have become more energy efficient. Over the last ten years, it is this market trend that is likely to have been the most significant common driver for declines in average use. In particular, there were improvements in the residential, and likely in the small commercial and institutional sectors, due to similar gas uses.

The OEE Index reveals a 1%/yr improvement in energy efficiency from 1990 to 2004. This 1% increase is in line with the decline in natural gas use per customer in the residential sector experienced by the gas companies over the same period, and is supportive of the 1.9% decline in all sectors together.

Based on the NRCan price forecast, high natural gas prices are likely to continue. This trend coupled with the trend toward higher efficiency gas equipment, tighter building envelopes and more pressure to achieve greater savings from DSM, means that it is likely that declines in average use will continue for the foreseeable future.

We may be moving into a different era. In the past historical experience was a good predictor of the gas market in the future. Today, it may not be as reliable due to short to medium term supply shortages in natural gas, restructuring in the Canadian economy due to a high Canadian dollar relative to the US dollar, greater consumer awareness of energy efficiency and government pressure on gas utilities and others to assist customers to reduce gas bills. These factors could bring us to the tipping point of an accelerated declining average use.

## Implications of declining average use for utilities and their customers

From a customer perspective, future declines in average use will likely mean that customers are using natural gas more wisely and are saving money on their gas bills. From a utility perspective, declining average use contributes to customer retention. This keeps natural gas competitive with alternative fuels. For utilities with DSM, their DSM programs will further help their customers to achieve wiser use.

A regulatory environment that enables the utility to recover all lost revenue due to declines in average use will protect the utility from earnings erosion due to the declines. Declining average use only becomes a problem for a gas utility if the declines are not adequately captured in rates.

Utilities, such as ATCO Gas, AltaGas ,Enbridge Gas Distribution and Union Gas, with the highest percentages of residential gas customers in markets where natural gas is the predominant residential fuel, have the largest potential impact on profitability because of any declining average use per customer in this sector.

## How to address declining average use

The utility response to declining average use per customer should be tailored to the market conditions and the regulatory environment in which the utility operates. These conditions differ across the country and among the individual utilities.

There are a number of options for addressing declining average use per customer in Canadian gas utilities. Five options are discussed in this paper, and they are: ignore declining average use, incorporate declining average use in the load forecast, decouple revenue from gas use, make adjustments to fixed and volumetric charges and address decoupling in PBR. These options are not completely distinct or independent from one another and more than one option can be operating at the same time for a particular company.

*Ignore declining average use*

One option for dealing with declining average use is to ignore it. Rate design, load forecasting, or revenue recovery would not be adjusted to reflect any decline in average use per customer.

In the short term, ignoring declining average use may be the preferred choice for a utility, either investor- or provincially-owned; if it is not posing a problem. For example, in a market that is nascent as the new infrastructure is being built based on the more recent gas use per customer data, any decline in customer usage year over year may be small and not have a significant impact on the utility's ability to recover its fixed costs in the short term. However, over time, the nascent utility will need to take declines in usage into account to protect the financial viability of the utility.

*Incorporate declining average use in the load forecast*

The most effective method of mitigating the effects of declining average use is through an offsetting increase in margin per unit rate. This can be accomplished through effective rate-setting either in cost-of-service or under PBR. The effectiveness of the methods will be largely dependent on the accuracy of the load forecast.

To the extent that the load forecast is accurate the utility and its customers are protected from declines in average use. In traditional rate-making the utility bears the full risk of underestimating declines in average use in the forecast and reaps the full benefits of overestimating declines. Underestimates lead to shortfalls in earnings for the utility until adjustments in rates are made to factor in a more appropriate estimate for decline in average use. Overestimates lead to higher than necessary rates for utility customers.

A utility can mitigate its risk associated with forecasting by trying to improve the accuracy of its forecast. For example, the utility could expand its efforts to obtain better data on both short-term and long-term trends regarding customer usage; it could work with other gas utilities across Canada to share knowledge on forecasting declining average use; and could encourage its provincial government and regulator to provide province-wide annual (and perhaps quarterly) data on trends in customer usage of energy, including natural gas. The regulator can also help to mitigate the utility forecasting risk by having annual rates cases.

Should experience reveal that the forecasts of declining average use are so unreliable that they result in significant margin erosion between offsetting adjustments, it may be necessary to track variances between forecast and actual declines in a declining average use tracker account, with true-ups made for under- and over-forecasting of the declines.

A simple tracking account, a Declining Average Use Tracker, would track variance between the forecast decline in average use and the actual decline for later disposition and true-up. True-ups would be made for both over-forecasting and under-forecasting the declines. Such an approach would eliminate the risk to the utility from the unpredictability of forecasting declining average use.

*Revenue decoupling*

Revenue decoupling breaks the link between the revenues earned by gas utilities and the amount of gas they distribute, thereby eliminating the need to recover a certain level of revenues from volumes. Rates would be set based on establishing a per customer revenue cap, and underages and overages from the cap would be trued up. However, there would still be risk associated with setting the appropriate revenue level per customer based on the forecast of decline in average use. To eliminate this risk, a Declining Average Use Tracker would be needed.

RD is a blunt instrument that eliminates risks associated with revenue recovery related to sales. It is too blunt an instrument if the sole purpose is to address declining average use. Unless, a utility is experiencing other revenue loss risk factors in addition to declining average use (e.g. weather risks, debt recovery, infrastructure renewal) resulting in undue risk or there are other policy reasons for choosing RD, RD may not be appropriate.

For Canadian gas utilities with well developed DSM portfolios, effective tools to allow for recovery of revenue losses due to DSM and incentives that achieve aggressive DSM, such decoupling mechanisms may be overkill if the sole purpose of the mechanism is to promote DSM. With increased government pressure to reduce customer gas bills, there may be renewed interest in RD in jurisdictions that carry out regulated DSM to create a more favourable climate for DSM. RD eliminates the utility disincentive for DSM as the utility's revenue is decoupled from the level of sales. The utility is protected from losses in margin from reducing gas use per account.

For Canadian utilities that are considering entry into regulated DSM, it may be appropriate to start with RD to eliminate any DSM disincentive.

*Adjustments to fixed and variable rate charges*

Making adjustments to rate design to increase the amount of revenue recovered through fixed charges can address risk associated with declining average use to varying degrees. Its effectiveness as a tool for managing declining average use will depend on how much revenue recovery is embedded in the fixed charges. In theory, improvements to rate design that lead to a one to one match of fixed costs with fixed charges and variable costs with variable charges are preferred. However, in practice, this may be difficult to achieve due to customer opposition to increases in fixed charges. In jurisdictions where electricity prices are very competitive with gas prices, a slight increase in fixed gas charges for residential customers could be the tipping point for large scale fuel switching to electricity for heating needs. Even in jurisdictions with more competitive gas prices compared with electricity prices, increasing fixed charges may be unwelcome with customers to varying degrees depending on the franchise area. In particular, raising fixed charges is not likely to be well received in the Canadian context due to its impact on low volume customers and low-income customers, in particular.

Unless the rate design went to a rate based solely on fixed charges – a straight variable rate design – adjustments to fixed and volume charges would leave the utility exposed to revenue recovery risks due to declining average use from the remaining volumetric portion in rates. However, even with a straight variable rate design, the utility would still be exposed to the risk associated with forecasting the declines in average use to be recovered in the fixed charge. An additional mechanism, such as a Declining Average Use Tracker, would be required to fully address this risk. Therefore, it is suggested as a matter of good rate design, rather than to deal with declining average use, to move incrementally and carefully to the extent reasonable for a particular utility and its market, toward a better matching of fixed costs with fixed charges.

*Addressing declining average use per customer in PBR*

An Index Cap PBR caps a utility's prices or revenues using a formula.[1] This formula, called the Price Cap Index (PCI) or Revenue Cap Index (RCI), depending on which variable is being capped, restricts the growth

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[1] Growth in PCI/RCI = P – X + Z
P is equal to the growth in an external inflation measure which can be economy-wide, industry-specific or for a peer group.
X is the X-factor which slows rate of revenue growth and which in North America is based on external industry productivity and input price information.
Z is the Z-factor which adjusts the PCI/RCI growth for external developments outside the company's control. Common Z factors include changes in government policy, change in industry accounting standards and natural disasters.

in allowed prices or revenues so that the growth must be less than or equal to the growth in the PCI or RCI. This is the most common form of PBR worldwide.

In Revenue Cap Index PBR or in Earnings Sharing PBR, rates are adjusted to ensure a specified level of revenue recovery. Within this process, adjustments to rates can be made which capture declining average use. Depending on the size of the variances incurred between adjustments, the utility, may wish to create a Declining Average Use Tracker to adjust for variations between forecast and actual declines in average use.

In a Price Cap Index PBR environment rates are capped and the actual revenues are determined based on the cap set. There is no adjustment made if the utility over- or under-earns. This type of rate setting, in its purest form, does not require a load forecast and therefore, provides no opportunity to make adjustment for declines in customer use over the PBR period. To correct for this problem, an adjustment to rates to account for declines in average use must be added. Three alternatives for making this adjustment have been identified and discussed in this paper. One alternative would be to include a declining average use factor in the calculation of the price cap. A second alternative is to adjust the X-factor in determining the price to account for declining average use. A third alternative would be to make declining average use a Z factor and accumulate differences between the forecast decline in average use and the actual decline in average use in a tracker for later disposition. In general, making declining average use a Z factor may be less attractive to regulators than the other alternatives, as regulators try to minimize the number of Z factors. The alternative adopted should be tailored to the specific circumstances of the utility.

# 1 Introduction

## 1.1 Purpose of report

Natural gas utilities across Canada are experiencing declining gas usage per customer. For some utilities the decline is across all sectors; for others the decline is centred on residential and on small commercial and small industrial customers. This decline has been happening in the market over time due to energy efficiency improvements in new construction and the turnover in stock to higher efficiency gas furnaces. The decline has gained greater notice in recent years because high and volatile gas prices are moving consumers to further reduce gas use. These prices are creating increased pressure on the utilities from governments and stakeholders to place greater emphasis on energy efficient gas use through the delivery of demand-side management (DSM) services to customers. In addition, there are specific factors pertinent to particular franchise areas that are magnifying the decline.

From a customer perspective, decline in average use is very positive; it means that customers are using natural gas more wisely and are saving money on their gas bills. From a utility perspective, decline in use per account has a positive benefit because this contributes to customer retention. For utilities with DSM, their DSM programs further help their customers to achieve wise gas use and savings on gas bills. However, if declines in average use are not properly addressed through effective rate regulation, this could jeopardize the continued effectiveness of gas DSM, discourage utilities from promoting wise gas use and result in significant lost earnings for the utility.

The Canadian Gas Association retained IndEco Strategic Consulting Inc. in June 2006 to explore at a high level the nature and extent of the decline in gas usage across Canadian natural gas utilities, to identify implications of this decline and to assess options for managing its negative consequences on the gas utilities. This paper documents the research and findings of this work.

## 1.2 Methodology

The research and analysis of declining average natural gas use in Canada was based on data provided by AltaGas, ATCO Gas, Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, Pacific Northern Gas (PNG) SaskEnergy, Terasen Gas and Union Gas. Enbridge Gas New Brunswick and Heritage Gas in Nova Scotia were excluded from the study as these utilities are relatively new and are focused on adding customers to the distribution system.[2]

In addition to obtaining data on declining average use provided by the utilities, IndEco conducted telephone interviews in July and August 2006 with Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, Terasen Gas and Union Gas, and in October 2006 with PNG and AltaGas. Interviews were used to obtain more detailed information on the gas utility experience with declining average use, the reasons the utilities have found for the decline, and steps taken and plans to address the decline. The data collection and interviews with the gas utilities was supplemented with a review of relevant published Canadian documents on declining average use and examples of the treatment of declining average use in US gas utilities, and informal consultations with various Canadian natural gas regulators.

It should be noted that the quantitative data submitted by each of the abovementioned Canadian utilities varied in completeness. In some cases, data were missing for earlier years within the range requested, while in other cases, sector specific data were not available. In analyzing and presenting this data herein, every effort is made to clearly present assumptions, omissions and limitations. Data were aggregated at the national level, as appropriate, to illustrate sector trends.

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[2] Heritage Gas Nova Scotia has been providing natural gas distribution services since December 2003. By August 2006, the utility had over 500 customers and 100km of pipeline.
**http://www.heritagegas.com/pipelinenews/pipelinenews.asp**

Enbridge Gas New Brunswick has been providing natural gas distribution services since 1999, serving eight municipalities with a total of over 470 kilometers of distribution mains installed as of the end of 2005.
**http://www.amazingenergy.ca/pdf/2006%20Construction%20Plan.pdf**

# 2 Actual decline in average natural gas use per customer in Canada

This chapter describes the decline in average gas use in Canada experienced in natural gas distribution utilities over the last 13 to 15 years, based on an analysis of actual total gas use. Section 2.1 briefly describes the methodology used to analyse the gas use. Section 2.2 presents a discussion of the non-normalized total gas use. Section 2.3 describes the relationship between total gas use and changes in total number of customers. Section 2.4 normalizes total gas use by customer. Section 2.5 normalizes total gas use by customer and weather, and Section 2.6 presents the conclusions of the analysis.

## *2.1 Methodology for determining the actual decline*

In July 2006, IndEco requested a standard set of data from seven gas utilities across Canada.[3] In October 2006, two additional utilities joined the study, PNG and AltaGas, and each was asked to provide the same standard set of data as the initial seven participants. Because of data availability, it was not possible to obtain a complete set of data from all utilities. The analysis has been carried out based on the data received. In addition to the data analysis, IndEco conducted telephone interviews in July-August 2006 with five of the seven initial utilities.[4] Interviews were conducted in October 2006 with PNG and AltaGas. The data were collected to determine whether the gas utilities across Canada were facing declining average use per customer and the interviews were used to identify what factors may be contributing to this decline.

PNG provided separate data for each of its two systems, PNG-West and PNG-Northeast (PNG-NE), and indicated that it would be inappropriate to aggregate and average this data across the company. The systems have very different market and geographic characteristics and are also treated separately for regulatory purposes.[5] As a result, IndEco treated each of the two systems within PNG as a 'separate company' for the purposes of the data analysis.

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[3] ATCO Gas, Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, SaskEnergy, Terasen Gas and Union Gas.

[4] Telephone interviews were held with Gaz Métro, Enbridge Gas Distribution, Manitoba Hydro, Union Gas, and Terasen Gas.

[5] The PNG-NE system is located in the gas production area of British Columbia and as a result this area has very low transmission costs. The PNG-NE system experiences colder weather than the PNG-West system.

Total natural gas use was analysed and then normalized by customer and by weather. The results of this analysis reveal that in Canada, natural gas use per customer in both the residential sector and across all sectors has been steadily declining over the last 13 to 15 years.

## 2.2 Non–normalized total natural gas use

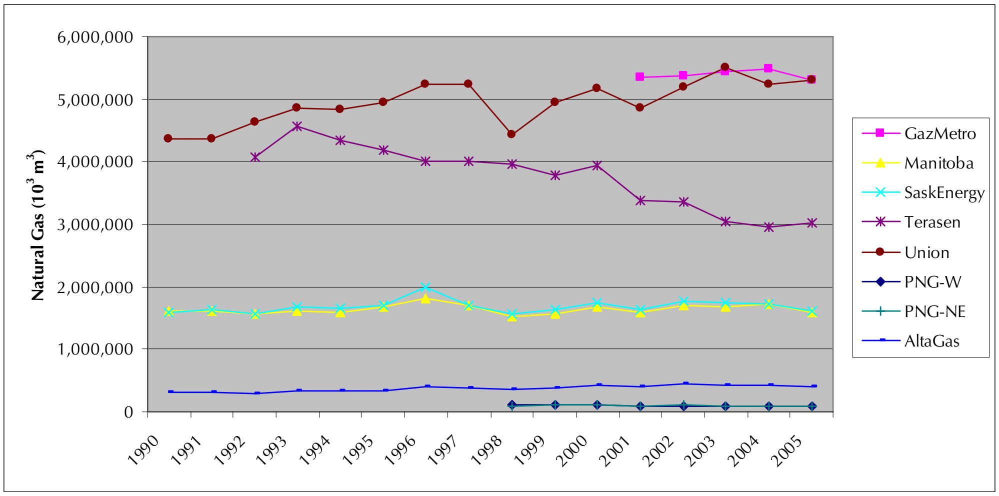
In the six utilities providing comprehensive data on actual natural gas use in and before 2005, a range in change in natural gas use was seen in both the residential and the non-residential sectors. Changes year to year in the numbers of customers served, in the climatic temperature (as characterized in this study as Heating Degree Days), and in the demand for natural gas per customer are contributing factors to the change.

As shown in Figure 1, total actual natural gas used across all sectors over the last 13 to 15 years ranged from a decline in total gas use of 25% for Terasen Gas to an increase in total gas use of 21% for Union Gas and 27% for AltaGas. The other utilities generally reported much smaller changes, with an average of a 5% increase over the period. Figure 2 aggregates the total natural gas use for the five utilities that provided IndEco with data from 1992 to 2005 and indicates that their total actual gas consumption over this period was relatively stable.

Change in actual natural gas use between 1990 and 2005 in the non-residential sectors ranged from a decline of 52% to an average value of an increase of 3%, to a maximum increase of 49%.[6]

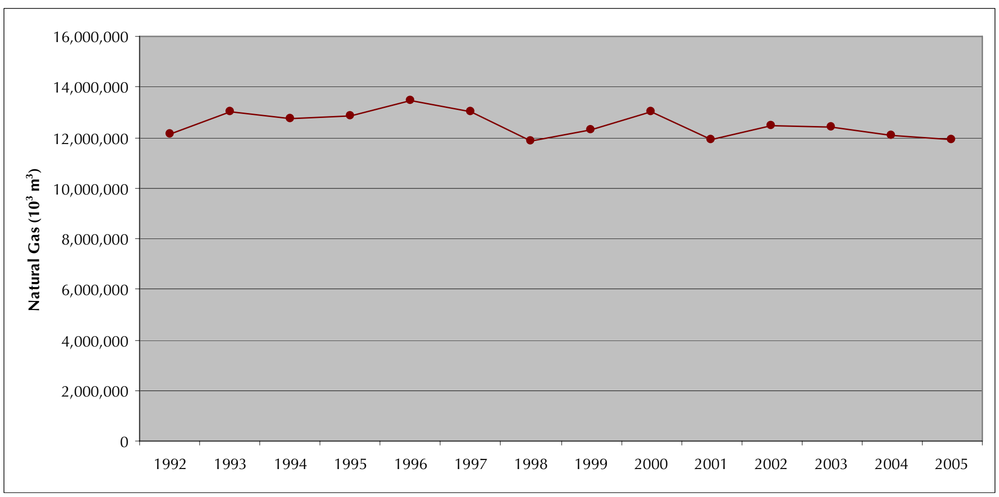
[6] Based on data provided by the participating gas utilities.

**Figure 1 Annual natural gas use in all sectors, 1990 to 2005**




Source: Survey of LDCs, July-November 2006.

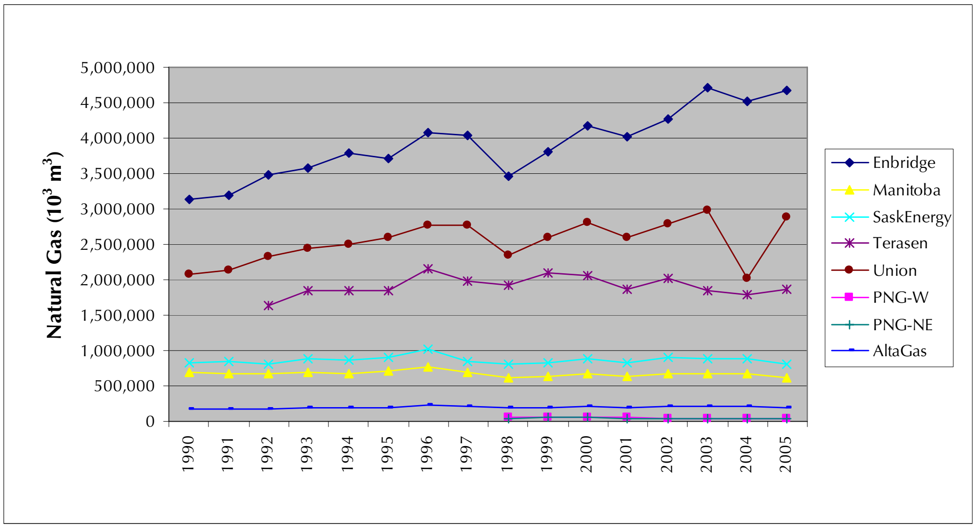
**Figure 2 Annual natural gas use in all sectors, 1992 to 2005 (total from 5 utilities across Canada)**




Source: Survey of LDCs, July-November 2006.

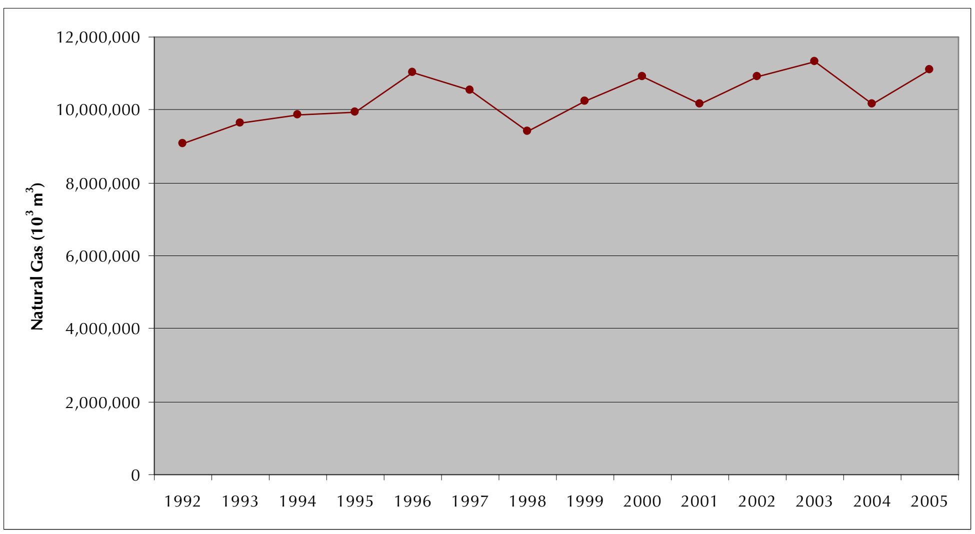
Actual natural gas use in the residential sector over the last 13 to 15 years, depicted in Figure 3, ranged from a decline in use of 11% to an increase in use of nearly 50%, and an average increase of 16%. Gas use for SaskEnergy remained at approximately the same level over the period, with Union, Terasen and AltaGas experiencing gradual increases in use, and Enbridge experiencing the largest increase. PNG and Manitoba Hydro showed decreases in use. When the utility data provided by the gas companies are aggregated over 1992 to 2005, as displayed in Figure 4, a gradual increase in total residential use is revealed.

**Figure 3 Annual natural gas use in residential sectors, 1990 to 2005**




Source: Survey of LDCs, July-November 2006.

**Figure 4 Annual natural gas use in residential sectors, 1992 to 2005 (total from 7 utilities across Canada)**




Source: Survey of LDCs, July-November 2006.

## *2.3 Total natural gas use and affect of change in number of customers*

Variation in the number of customers is one factor that affects actual natural gas use year to year. The increase in the total numbers of customers from 1992 to 2005 for the six utilities providing data over this period ranged from 14 to 68% with an average increase of 37%, while increases in customers from the residential sector ranged from 14 to 72%

with an average of 39%. Numbers of total customers for each utility and the average annual increase are outlined in Table 1. Average annual total customer number changes ranged from -0.6% to 3.5% with an average increase across all utilities of 1.7%.

**Table 1 Customer base by utility, 1990 to 2005**

| LDC | Customers 1990 | Customers 1995 | Customers 2000 | Customers 2005 | Average annual % increase | % Residential in 2005 |
|---|---|---|---|---|---|---|
| ATCO | n/a | n/a | 906,550[1] | 939,598 | 0.7 % | 92%[1] |
| Enbridge | 1,034,654 | 1,232,989 | 1,479,413 | 1,735,907 | 3.5 % | 91% |
| Gaz Métro | n/a | 148,516[2] | 151,082 | 162,040 | 1.3 % | 66%[1] |
| Manitoba Hydro | 218,248 | 229,418 | 245,720 | 254,936 | 1.0 % | 90% |
| SaskEnergy | 283,682 | 293,949 | 314,261 | 323,593 | 0.9 % | 82% |
| Terasen | 619,032[3] | 685,400 | 755,079 | 791,593 | 1.9 % | 90% |
| Union | 789,462 | 963,762 | 1,122,718 | 1,247,916 | 3.1 % | 91% |
| PNG-West | n/a | n/a | 23,435 | 22,147 | -0.6% | 87% |
| PNG-Northeast | n/a | n/a | 16,031 | 16,945 | 1.6% | 87% |
| AltaGas | 44,355 | 49,205 | 57,012 | 61,992 | 2.3% | 89% |

1. 2004 data from IndEco and B. Vernon & Associates. *DSM Best Practices*. CGA. 2005.
2. 1998 data.
3. 1992 data.

Source: July – November 2006 survey of LDCs.

The larger the proportion of residential customers a gas utility has, the greater the potential impact on profitability because of any declining average use per customer in this sector. The differences in the natural gas markets and the number of residential customers is primarily based on provincial fuel mix and the dominant residential heating fuel, which is largely based on the relative price of natural gas compared with electricity.[7] For example, Gaz Métro has a significantly smaller proportion of residential customers in their total customer base, compared to the other utilities. This reflects the fact that electricity is the dominant residential heating source in Quebec. This relative use of natural gas in the residential sector across Canada is depicted in Table 2.

[7] The average residential tariffs for natural gas are quite similar across the companies, with the exception of SaskEnergy and ATCO Gas, which are somewhat lower due in part to low transportation and storage costs.

**Table 2 Residential sector secondary energy use by source, 2003**

| Region | Total energy use (PJ) | Share by energy source (%) | | | | |
|---|---|---|---|---|---|---|
| | | Electricity | Natural Gas | Heating Oil | Other[1] | Wood |
| Canada | 1457.6 | 37.2 | 46.0 | 8.4 | 0.8 | 7.5 |
| Newfoundland | 22.1 | 55.4 | 0.0 | 26.9 | 0.7 | 17.1 |
| Nova Scotia | 42.9 | 33.7 | 0.0 | 53.6 | 1.8 | 10.9 |
| PEI | 4.6 | 12.1 | 0.0 | 73.7 | 3.6 | 10.6 |
| New Brunswick | 33.5 | 57.4 | 1.7 | 20.3 | 1.1 | 19.5 |
| Quebec | 349.0 | 59.4 | 8.1 | 13.9 | 0.3 | 18.4 |
| Ontario | 576.4 | 29.7 | 60.6 | 5.5 | 0.9 | 3.3 |
| Manitoba | 48.0 | 44.5 | 48.6 | 0.5 | 0.6 | 5.9 |
| Saskatchewan | 45.9 | 22.8 | 71.4 | 0.8 | 2.6 | 2.4 |
| Alberta | 190.2 | 14.3 | 84.5 | 0.0 | 0.9 | 0.2 |
| BC | 141.7 | 40.8 | 53.1 | 0.7 | 0.8 | 4.6 |
| Territories | 3.2 | 32.1 | 5.2 | 46.6 | 7.6 | 8.6 |

1. Other includes coal and propane.

Source: Comprehensive Energy Use Database, NRCan.
http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?attr=0

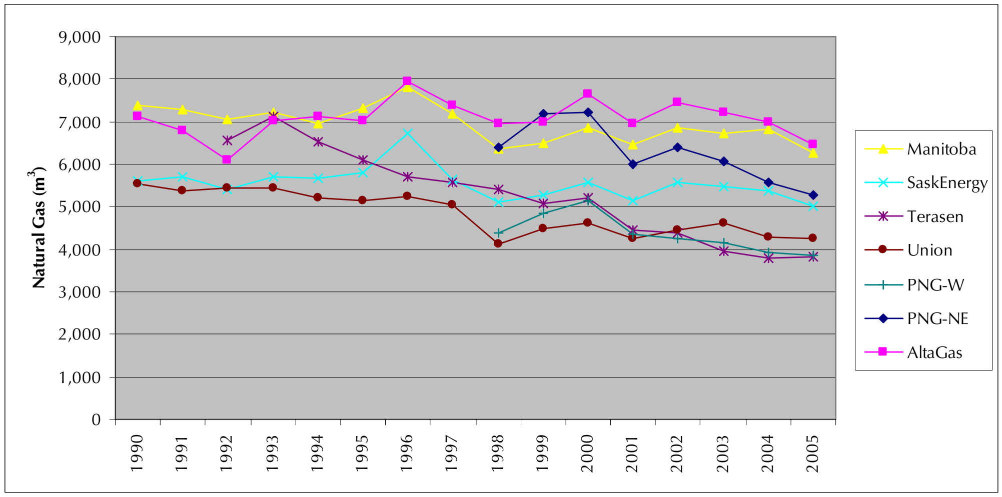
As Table 1 and Table 2 demonstrate, the residential market for gas utilities in Canada is an important market segment. In Canada about 46% of the energy use in the residential sector is natural gas, ranging from only 8.1% in Quebec to 84.5% in Alberta. All gas utilities in this study have more residential customers than other types of customers ranging from only 66% of total customers in Quebec to 92% in Alberta. Utilities, such as ATCO Gas, Enbridge Gas Distribution, SaskEnergy, Terasen Gas, Union Gas and AltaGas, with the highest percentages of residential gas customers in markets where natural gas is the predominant residential fuel, have the largest potential impact on profitability because of any declining average use per customer in this sector.

## 2.4 Total gas use normalized by customer

With the large increase in the number of customers removed from the equation, actual natural gas use per customer (normalization based on number of customers) allows an examination of trends in individual customer demand. Trends clearly show a decline in actual natural gas use per customer.

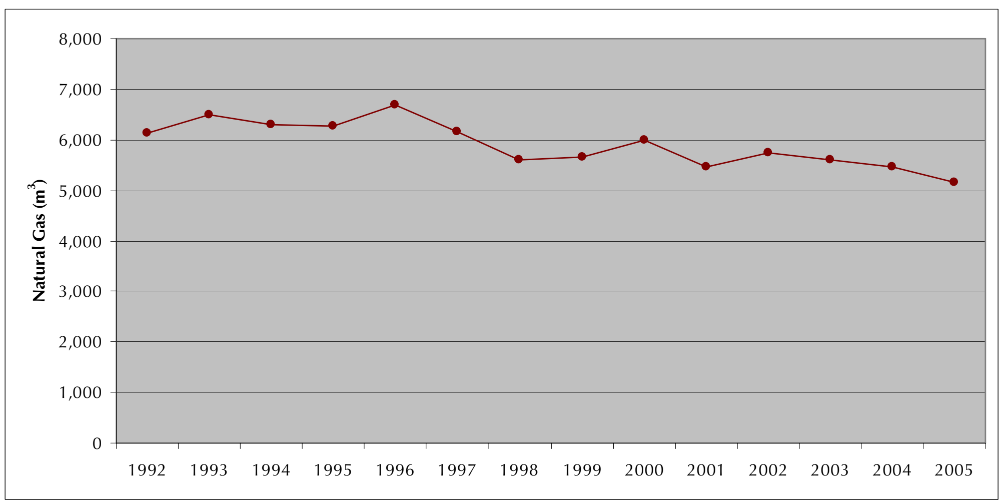
Decline in gas use per customer across all sectors from 1990 to 2005 ranged from 9% to 42%, with an average decline of 20%. The decline in the residential sector gas use per customer ranges from 11% to 24%, and an average of 16%. Gas use per customer in both the residential sector and across all sectors has been steadily declining over the last 13 to 15 years, as shown in Figure 5 through Figure 8.

**Figure 5 Annual average natural gas use per customer in all sectors, 1990 to 2005**



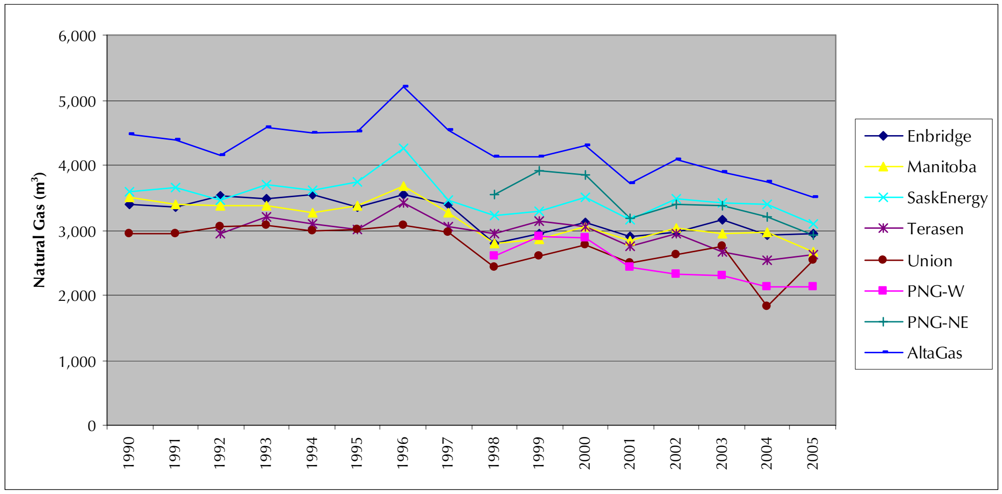

Source: Survey of LDCs, July-November 2006.

**Figure 6 Annual average natural gas use per customer in all sectors, 1992 to 2005 (average from 5 utilities across Canada)**



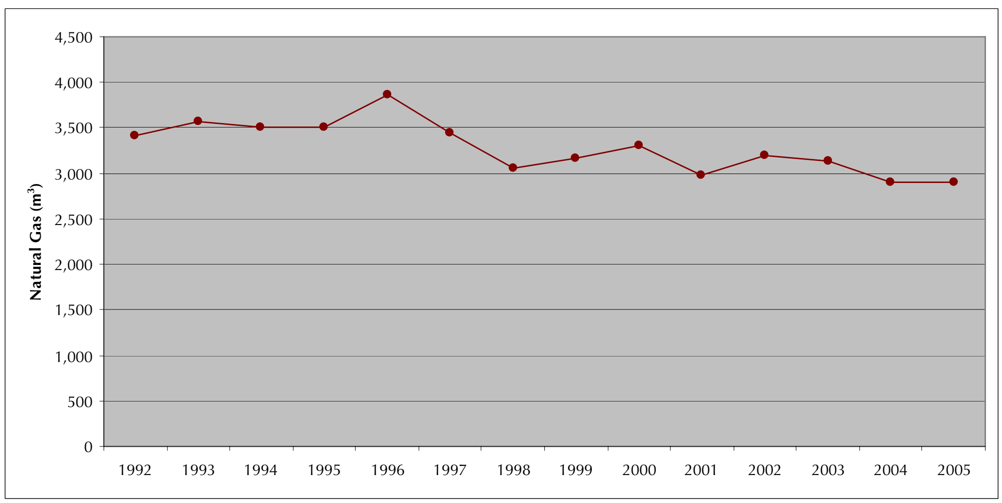

Source: Survey of LDCs, July-November 2006.

**Figure 7 Annual average natural gas use per customer in residential sectors, 1990 to 2005**




Source: Survey of LDCs, July-November 2006.

**Figure 8 Annual average natural gas use per customer in residential sectors, 1992 to 2005 (average from 6 utilities across Canada)**




Source: Survey of LDCs, July-November 2006.

## 2.5 Total gas use normalized by customer and weather

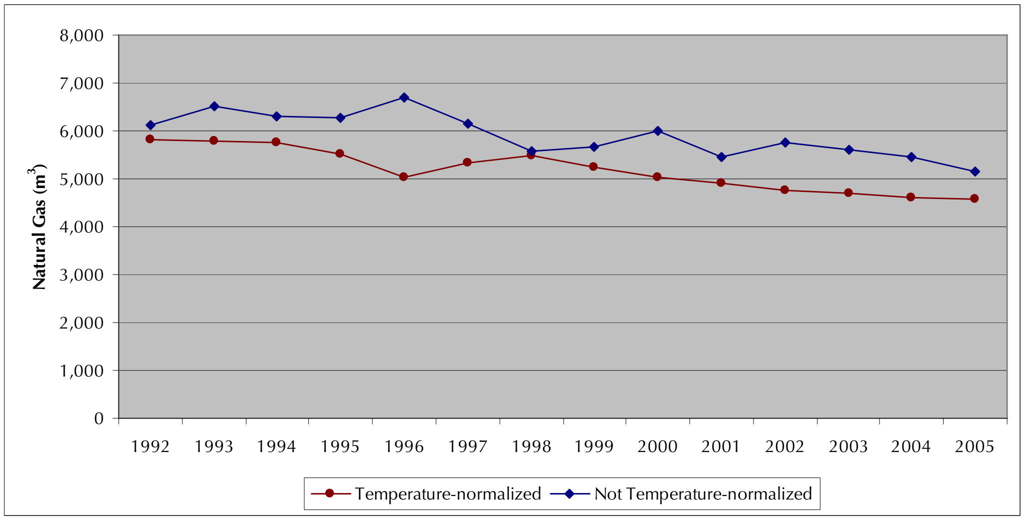
Taking the actual use data normalized by number of customers and further normalizing by climatic temperature gives a truer indication of gas use per customer over the last 13 to 15 years. Due to the variability in the methods of normalization each utility used to determine their reported normalized natural gas use values, the data were neither comparable across each utility nor in aggregate. Rather than using the reported normalized data, IndEco normalized for weather the reported actual natural gas use per customer from each utility by the utility's reported annual number of Heating Degree Days to provide a basis for comparison of natural gas use year to year across Canada. Specifically, each natural gas use value was normalized to 4000 Heating Degree Days, roughly the average reported across Canada, effectively providing actual natural gas use per customer per 4000 Heating Degree Days.[8]

These temperature-normalized natural gas values are illustrated along with non temperature-normalized values in Figure 9 and Figure 10, for all sectors and the residential sector, respectively. As the figures show, trends in temperature-normalized annual natural gas use per customer for both the residential sector and all sectors together are similar in nature to those non temperature-normalized. Decline in natural gas use per customer across all sectors ranges from 4 to 42% with an average of 19%, while decline in the residential sector ranged from 12 to 21% with an average of 16%. These numbers are very similar to those before temperature-normalization, showing that change in climatic temperatures over time (for example, due to climate change or natural year-to-year variability), in general, has had very little effect on natural gas use in Canada.

The minimal impact of weather is highlighted by the decline in average natural gas use per customer found in AltaGas' service territory. AltaGas has 14 operating districts spread geographically throughout Alberta from the border with the Northwest Territories to the U.S. border. Despite this wide geographic range, and accompanying difference in average temperature, AltaGas has found that they are experiencing the same decline in average use throughout all districts in their service territory.

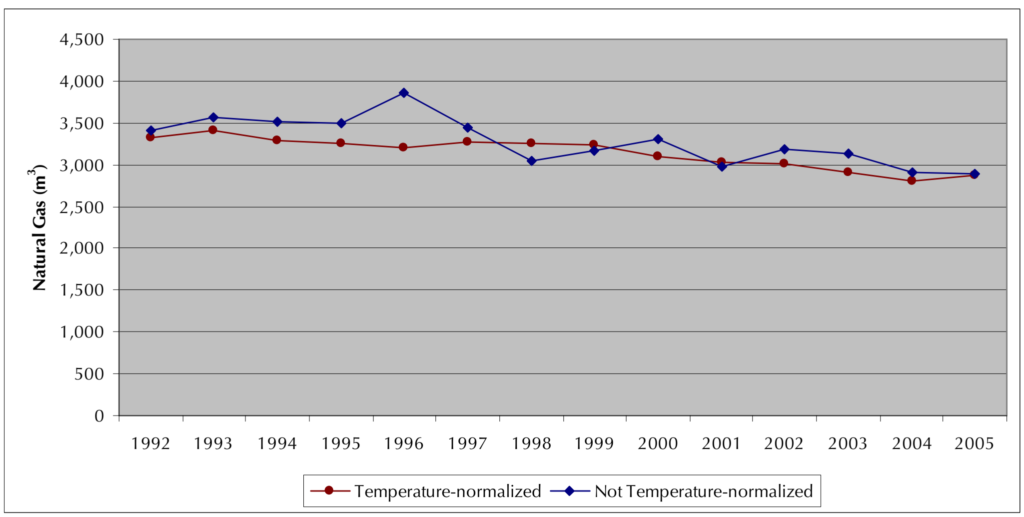
[8] It should be noted, however, that the utilities use different methodologies to calculate their heating degree days depending on their local circumstances. Thus, a reliable comparison of normalized natural gas use cannot be made, region-to-region, or utility to utility.

**Figure 9 Temperature-normalized and non temperature-normalized annual average natural gas use per customer in all sectors, 1992 to 2005, (average from 5 utilities across Canada)**




Source: Survey of LDCs, July-August 2006.

**Figure 10 Temperature-normalized and non temperature-normalized annual average natural gas use per customer in residential sectors, 1992 to 2005, (average from 6 utilities across Canada)**




Source: Survey of LDCs, July-August 2006.

## *2.6 Conclusions on declining average use*

The analysis of the data provided by the natural gas distribution utilities shows a decline in average use of natural gas across all sectors of 19% over the past 13 to 15 years, while across the residential sector, that decline has been 16%. This corresponds roughly to a decline in average use of 1.9% per year on average for all sectors and to a decline in average use in the residential sector of 1.1% per year on average.

According to the American Gas Association (AGA), natural gas use per customer in the residential sector in the United States declined 21% over the 21 year period from 1980 to 2001, averaging 1% per year.[9] This number is relatively consistent with the 1.1% per year average decline in use per residential customer in Canada. These results point to the robustness of the Canadian numbers.

The analysis of the Canadian situation has revealed that changes in number of customers and climatic variation are not the main drivers of declining average use. As numbers of customers have continually increased and climatic temperature variation has been shown to generally have a very minor, if any, effect on natural gas use change, other factors must be driving the decline. These drivers are identified and discussed in Chapter 3.

[9] American Gas Association: Policy Analysis Group, *Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020*. September 2004. p.1. Factors contributing to the decline include appliance efficiency, appliance penetration, and thermal efficiency. Home size increases dampened the effect of the decline per customer. ibid. p. 4. The AGA forecasts the average annual decline in use per residential gas customer to be .46% from 2001 to 2010 and .67% from 2010 to 2020, indicating that the decline is expected to continue but at a slower rate, with an annual average decline of .5%/yr, from 1980 to 2020. (ibid. p.1-3).

# 3 Drivers of declining average gas use in Canada

This chapter discusses the main drivers of declining average usage in Canada. Drivers at both the macro level (across Canada) and at the micro level (particular to certain utilities) are discussed.

A description of the common macro level drivers is presented below along with the impact that they are expected to have on declining average gas use in the future. These drivers are described in Sections 3.1 to 3.3 and include the price of natural gas, trends in energy efficiency and demand side management. The specific drivers for declines in average use affecting particular utilities are discussed in Section 3.4. Conclusions regarding these macro and micro level drivers are presented in Section 3.5.

## *3.1 Price of natural gas*

One factor that can lead to declining natural gas use per customer is the price of natural gas. To the extent that the price signal will encourage customers to become more efficient gas users, we can expect price to have had an impact on historical per customer gas use and to have an impact on future per customer gas use.

During the 1990's, natural gas prices were relatively low, with an average price of CDN $1.68/GJ between 1991 and 1999.[10] However, since mid-2000, prices have been much higher, reaching a high in 2004 of CDN $6.52/GJ, up from CDN $5.00/GJ in 2000. This price spike occurred because of the inability of North American gas production to meet the increasing demand, coupled with high world crude oil prices.[11]

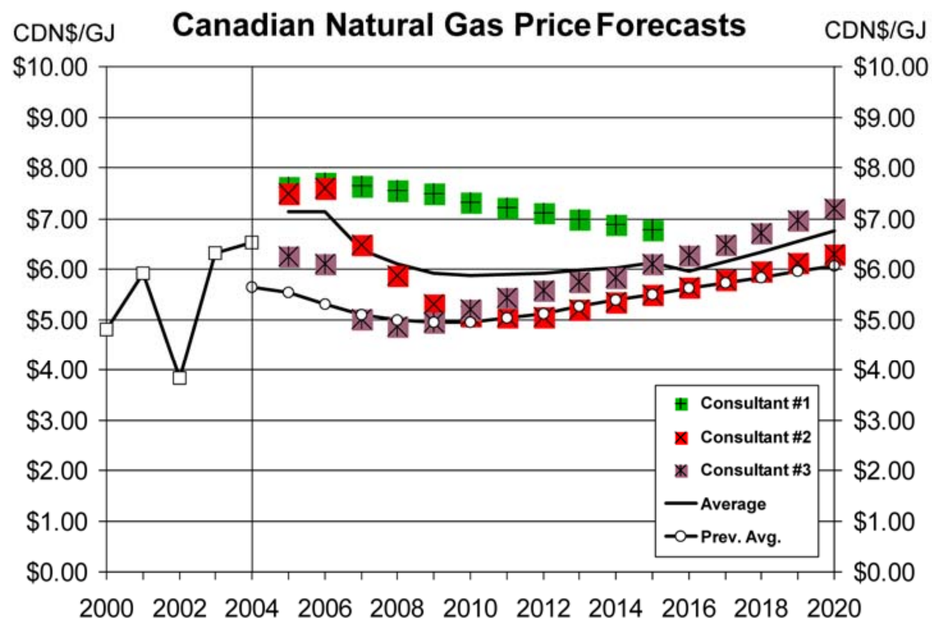
In the 1990's with gas prices relatively low, it is unlikely that price would have been a main driver in declining average use. However, since 2000 with record high natural gas prices, price becomes a more important driver for declines in average use. The impact of price on declines in average use in the future is likely to become more important based on the forecast of continued high gas prices.

[10] Based on intra-Alberta, AECO or NIT, which is Canada's natural gas pricing point) Natural Resources Canada. *Canadian Natural Gas Review of 2004 & Oulook to 2020*. January 2006. p.ii.

[11] Natural Resources Canada. *Canadian Natural Gas Review of 2004 & Outlook to 2020*, January 2006. p. v.

Figure 11 shows NRCan's forecast for Canadian natural gas prices to 2020. The average forecast indicates that prices are expected to be above CDN $5.00/GJ over the forecast period, with a slight dropping off of prices between 2007 and 2010, and then gradual price increases to 2020. Gas prices are forecast to remain high over the medium-term, primarily because of the inability of North American gas production to meet increasing demand.

**Figure 11 Canadian natural gas price forecasts**




**Source:** Various consultants. **Notes:** (1) Historical are AECO actuals from GLJ. (2) Forecast prices are AECO. (3) Some forecasts were converted from $US to $CDN using an exchange rate of US $1.00 to CDN $1.30 over the entire forecast period. (4) Nominal dollars.

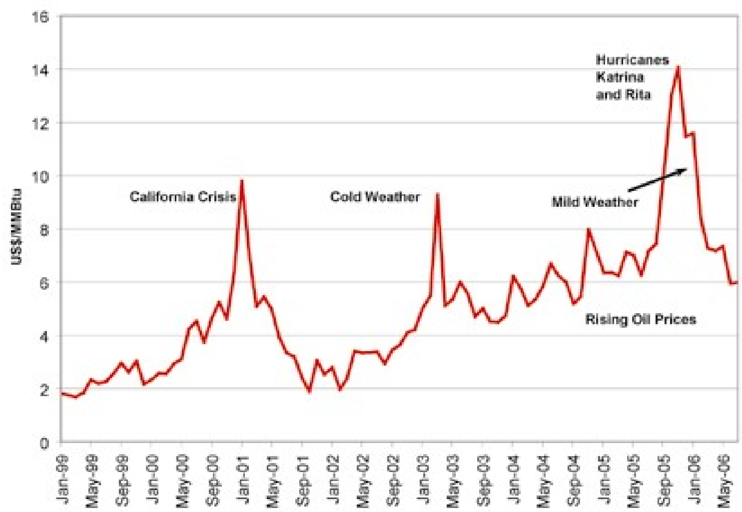
Source: Natural Resources Canada. *Canadian Natural Gas Review of 2004 & Outlook to 2020*, January 2006. p. 47.

During the period from 1999 to 2006, there was significant volatility in North American gas prices. As shown in Figure 12[12], the general trend in increasing prices is accentuated with small peaks and troughs due to seasonal variations and large peaks due to world and extreme weather events. Overall, price has tripled (from approximately US$2/MMBtu to US$6/MMBtu) since late 2001. Since 2001, North American natural gas supply growth has not kept pace with growth in demand, contributing to high and volatile gas prices. Price volatility creates uncertainty in the market. Customers lose confidence and those most risk adverse take the strongest steps to minimize risks, especially during periods of high prices.

[12] National Energy Board website. **www.neb-one.gc.ca/energy/EnergyPricing/HowMarketsWork/NG_e.htm**. Accessed August 15, 2006.

As a result, it is likely that since 2000, natural gas price volatility has been a contributing factor to declines in average use. If price volatility continues over the forecast period to 2020, it is likely to increase the impact on declining customer natural gas use due to high gas prices.

**Figure 12 Canadian natural gas price volatility**




Source: National Energy Board. *3 Day Average Natural Gas Price*. http://www.neb-one.gc.ca/energy/EnergyPricing/HowMarketsWork/NG_e.htm

## 3.2 Canadian trends in energy efficiency

Over time, Canadian homes and businesses have become more energy efficient. Over the last ten years, it is this market trend that is likely to have been the most significant common driver for declines in average use. In particular, there were improvements in the residential, and likely in the small commercial and institutional sectors, due to similar gas uses.

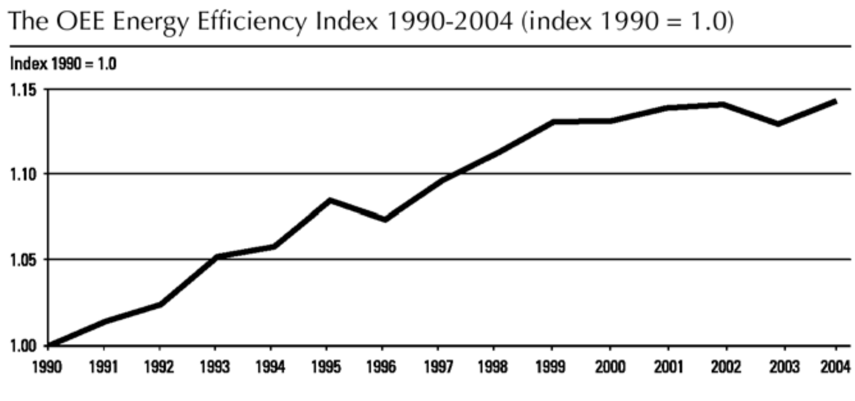
### Overall energy efficiency gains

Between 1990 and 2004, there have been significant improvements in energy efficiency. Natural Resources Canada's Office of Energy Efficiency (OEE) reports on energy efficiency trends in Canada, with its most recent 2006 publication reporting on trends from 1990 through 2004.[13] The report estimates the impact of energy efficiency on energy consumption for each of the residential, commercial/institutional, industrial and transportation sectors, as well as for all of these sectors in

[13] Natural Resources Canada Office of Energy Efficiency, *Energy Efficiency Trends in Canada 1990 to 2004*, August 2006.

aggregate. The aggregate evaluation is expressed as a single index for all of Canada, referred to as the OEE Energy Efficiency Index (Index).[14] The OEE reports that the Index grew relatively steadily from 1990 to 2004, averaging an increase in 1% per year, with a total increase of 14%.[15] This growth is illustrated in Figure 13.

**Figure 13 The OEE Energy Efficiency Index 1990-2004**




Source: Natural Resources Canada Office of Energy Efficiency, Energy Efficiency Trends in Canada 1990 to 2004, August 2006. p.10.

As energy use continued to increase due to increases in sector activity (number of residences, new commercial and industrial applications, etc.) and other factors, improvements in energy efficiency served to slow this energy use increase. Without improvements in energy efficiency, energy use (normalized by weather) was projected to increase by 36%, while with improvements in energy efficiency, energy use actually increased by only 23%.[16] Thus energy efficiency improvements saved an additional 13% increase in energy use between 1990 and 2004.

Energy efficiency improvements were largest in the residential sector. Improvements in energy efficiency in other sectors have shown to be more variable, with different influencing factors.

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[14]This Index shows changes in the efficiency of how Canadians use energy to heat and cool their homes and workplaces and to operate appliances, vehicles and factories. The analysis by the OEE does not distinguish between energy end-use from electricity or natural gas, nor from fuel type used in generation of energy. Natural gas end-use burner tips and appliances account for a much smaller percentage of total energy end-use than the electricity end-uses.

[15] Natural Resources Canada, *Socio-Economic Trends Versus Space and Water Heating Energy Use,* May 2004. p.10.

[16] Natural Resources Canada, *Socio-Economic Trends Versus Space and Water Heating Energy Use*, May 2004. p.5.

### Energy efficiency gains in the residential sector

In the residential sector, improvements in energy efficiency are estimated to have resulted in a 21% reduction in energy use. This improvement is due to upgrading in the thermal envelope of houses and to the increased efficiency of residential space heating and cooling equipment, water heating equipment and appliances. In the residential sector, space heating accounts for 59% of energy end-use, water heating accounts for 22% of energy end-use, and appliances account for 13% of energy end-use, with major appliances representing 8%.[17]

While no specific energy efficiency improvement data are discussed for a small commercial/institutional sector, it is likely that both the residential and the small commercial/institutional sectors have experienced similar improvements in energy efficiency (due to building code improvements, retrofitting with more energy efficient equipment etc.) as the use of natural gas in both of these sectors is primarily for space and water heating (space heating and cooling equipment accounting for 61% and lighting accounting for 13%[18]).

Improvements in the energy efficiency of building stock have made a significant reduction in natural gas use per customer in the residential sector due to improvements in building design. For example, homes built between 1946 and 1969 had a total natural gas intensity in Ontario of 0.9GJ/m2, in the Prairies an intensity of 1.28GJ/m2, and in BC 0.72GJ/m2; whereas homes built between 1990 and 2003 had an intensity of 0.62GJ/m2 in Ontario, 0.91GJ/m2 in the Prairies and 0.65GJ/m2 in BC.[19]

These reductions in natural gas intensity are due to improvements in building envelope as well as the efficiency of heating equipment. Energy efficient practices and technology improvements in mainstream construction resulted in a drop of approximately 60% in air leakage in housing built in 2000 to 2004 from housing built prior to 1945, and an

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[17] Natural Resources Canada, Socio-Economic Trends Versus Space and Water Heating Energy Use, May 2004, p.2, p.13.

[18] Natural Resources Canada, Office of Energy Efficiency, The State of Energy Efficiency in Canada, Report 2006, 2006, p.13.

[19] Natural Resources Canada Office of Energy Efficiency. 2003 Survey of Household Energy Use. http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/sheu03/publ…

average decrease in energy use in this housing of 13% after an EnerGuide for Houses retrofit.[20]

In Canada in 1990, 41.1% of the residential space heating system stock was a normal efficiency gas furnace and only 2.1% was high efficiency; in 1994 the normal efficiency percentage had dropped to 37.4%; the high efficiency furnace percentage had risen to 3.4%.[21] In Union Gas's franchise area in 2006, 90% of all new houses and 2/3 of the furnace replacement market are going to high efficiency gas furnaces.[22]

### Continuation of improvements in energy efficiency

High gas prices, together with higher efficiency gas furnaces/boilers going into new construction, continued turnover of lower efficiency natural gas furnaces/boilers to higher efficiency ones, and tighter building envelopes will likely result in the continuation of declines in average gas use, particularly in the residential as well as the small commercial/institutional sectors. There is some evidence to suggest that the implementation of these improvements in energy efficiency of gas use may accelerate in the short and medium term due to sustained high natural gas prices, greater consumer awareness of energy efficiency, and government pressure on gas utilities and others to assist customers to reduce gas bills.

Declining average customer use of gas due to the continuation of this energy efficiency trend, and the possible acceleration of the adoption of energy efficiency improvements, will make it increasingly difficult for gas utilities to recover their fixed costs from the volume-based charges in rates for residential and small commercial/institutional customers.[23]

## *3.3 Regulated demand side management in Canadian gas utilities*

Demand side management (DSM) activities are another factor that can result in declining average use per customer. These activities can contribute to increases in the use of more energy efficient gas equipment and to changes in customer behaviour that lead to reductions of gas

[20] Natural Resources Canada, Office of Energy Efficiency, The State of Energy Efficiency in Canada, Report 2006, 2006, p.17.

[21] Natural Resources Canada Office of Energy Efficiency. Residential End-Use Model, Ottawa, February, 2006. http://oee.ncrcan.gc.ca/corporate/statistics/neud/dpa/tableshandbook2/r...

[22] Telephone interview with Union Gas. August 25, 2006.

[23] Assumes all other things being equal.

usage. Historically, regulated gas DSM has not been a major driver of overall declines in average use as it is a relatively new pursuit for many Canadian jurisdictions and did not exist in Canada before 1995.

The DSM regulatory environment under which a utility operates influences whether utilities implement DSM programs, the programs that are selected for implementation and the preferred outcome of DSM activities. In jurisdictions with DSM regulated by an arms-length agency (e.g. Ontario, BC and Quebec), the primary driver for DSM tends to be achieving cost effective energy savings. At SaskEnergy, on the other hand, the primary driver for its DSM program is residential customer satisfaction and retention. Table 3 summarizes the DSM regulatory environment of each of the companies included in the analysis.

**Table 3 Regulatory environment of natural has companies conducting DSM in Canada**[24]

| LDC | DSM approval agency | DSM since |
|---|---|---|
| ATCO | n/a | 2002 |
| Enbridge | Ontario Energy Board | 1995 |
| Gaz Métro | Régie de l'énergie Québec | 1999 |
| Manitoba Hydro | Manitoba Public Utilities Board | n/a |
| SaskEnergy | Crown Investment Corporation | 2001 |
| Terasen | British Columbia Utilities Commission | 1997 |
| Union | Ontario Energy Board | 1997 |

As Table 4 shows, from 2000 through 2005, more than 150 million dollars were invested in DSM by natural gas utilities in Canada. Annual DSM expenditures have increased steadily over this period, with the total expenditure in 2005 ($38.5M) being more than twice that of 2000 ($16.6M). This growth is due to both an increase in the number of companies participating in DSM over the time period, as well as an increase in DSM budgets within individual companies over the period.

[24] PNG and AltaGas do not conduct DSM.

**Table 4 DSM expenditures and energy savings, 2000 to 2005**[1]

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|---|
| Number of utilities with DSM programs | 4 | 6 | 7 | 7 | 7 | 7 |
| LDC DSM expenditures (millions of $) | $ 16.6 | $ 22.1 | $ 23.4 | $ 26.0 | $ 30.9 | $38.5 |
| Natural gas annual end-use savings from LDC DSM programs (millions of $m^3$/yr) | 91.8 | 138.2 | 150.2 | 153.4 | 170.9 | 192.5 |
| Cost per $m^3$ | $ 0.18 | $ 0.16 | $ 0.16 | $ 0.17 | $ 0.18 | $0.20 |
| Natural gas annual end-use savings from LDC DSM programs (millions of GJ/yr) | 3.48 | 5.24 | 5.69 | 5.81 | 6.47 | 7.13 |
| Cost per GJ | $ 4.76 | $ 4.22 | $ 4.12 | $ 4.47 | $ 4.78 | $ 5.40 |

1 2001-2004 data from IndEco and B. Vernon & Associates. *DSM Best Practices*. CGA. 2005. 2005 data from survey of LDCs, July-August 2006.

2 2005 data does not include any data from ATCO, or data on end-use gas savings from Manitoba Hydro.

Table 5 illustrates DSM expenditures by company and as a percent of utility revenue. While the largest DSM budget is more than 15 times that of the smallest DSM expenditure, the percent of revenue that DSM expenditures represent is much more consistent across the companies, suggesting that much of the variance in DSM budgets is explained by variance in company size. On average, the utilities spent 0.38% of their total revenue and 1.29% of their revenue less commodity cost on DSM in 2005.

**Table 5 2005 DSM expenditures, by company, as a proportion of revenue**

| LDC | DSM expenditure ($ millions) | Total utility revenue ($ millions) | % of total utility revenue | Utility revenue less cost of gas ($ millions) | % of utility revenue less cost of gas |
|---|---|---|---|---|---|
| ATCO | $ 4.30[1] | $ 1,550[1] | 0.28%[1] | $ 407[1] | 1.06%[1] |
| Enbridge | $ 15.50 | $ 3,075 | 0.50% | $ 881 | 1.76% |
| Gaz Métro | $ 8.50 | $ 1,578 | 0.54 % | $ 448 | 1.90% |
| Manitoba Hydro | $ 2.50 | $ 555 | 0.45 % | $ 126 | 1.98% |
| SaskEnergy | $ 0.85 | $ 537 | 0.16 % | $ 172 | 0.49% |
| Terasen | $ 3.00 | $ 1,420 | 0.21 % | $ 463 | 0.65% |
| Union | $ 8.10 | $ 2,084 | 0.39 % | $ 847 | 0.96% |
| PNG | n/a | n/a | n/a | n/a | n/a |
| AltaGas | n/a | n/a | n/a | n/a | n/a |

1. From 2004, 2005 data not available. From www.ATCOgas.com/Regulatory/03-04_AG_GRA/APPL_UPDATED/SCH_REV.xls

Source: July – November 2006 survey of LDCs.

In order for regulated DSM to achieve significant declines in customer gas use, gas utilities need a regulatory regime that supports this endeavour. [25] The utility needs to be protected from revenue losses due to DSM and to be rewarded for successful DSM. Several utilities such as Enbridge Gas Distribution, Gaz Métro, and Union Gas have a lost revenue adjustment mechanism (LRAM) that allows the utilities to track and recover lost revenues due to their DSM activities. As concluded in the recent Ontario Energy Board decision on natural gas DSM,

> "*As long as a utility's fixed costs are not fully recovered through fixed charges (and part of the fixed costs are therefore being recovered through the variable charges) there is an inherent conflict for the utility between sales growth and conservation. The existence of a mechanism to neutralize this conflict through an LRAM mechanism is therefore essential to the success of DSM*."[26]

Terasen Gas and PNG have a broader revenue recovery mechanism, the Revenue Stabilization Adjustment Mechanism (RSAM), which allows them to recover revenue losses from all sources, including DSM. All of these utilities, (except PNG which does not have regulated DSM), have an incentive mechanism to reward the utility for DSM performance; some mechanisms have been more effective than others in promoting aggressive DSM.[27]

## Future role of regulated DSM in achieving declines in average use

The importance of regulated DSM as a driver in the decline in average use may increase in the future. Sustained high natural gas prices may lead to heightened government pressure on gas utilities to deliver more aggressive DSM and may drive customers to demand more energy efficiency services from their gas utility. With an LRAM and the right

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[25] At least 29 US gas utilities have provisions that allow for the recovery of DSM program costs as well as the recovery of lost revenues caused by the reductions in sales due to DSM. AGA. *Natural Gas Roundup*, p.12.

[26]Ontario Energy Board, Decision with Reasons, EB-2006-0021. P.39. August 26, 2006.This was a generic proceeding to address a number of current and common issues related to demand side activities for natural gas utilities. In this proceeding, the OEB renewed its commitment to LRAM and to a strong incentive mechanism for the gas utilities to excel in DSM.

[27] Historically, the most successful incentive mechanism was Enbridge Gas Distribution's shared savings mechanism (SSM). In the Ontario Energy Board's most recent decision on natural gas DSM of August 25, 2006 (EB-2006-0021), the Board approved a new SSM for Enbridge and Union which rewards them for achievement of progressively higher percentages of the DSM target, based on a curve starting at up to 25% of the target ($225,000) and moving in 25% increments to up to $4,750,00 for achievement of the target, and capped at achieving in excess of 125% of the target $8,500,000). p.28.

DSM incentives, gas utilities could realize much more significant reductions in average customer usage from DSM.

## 3.4 Specific local drivers of declines in average gas use

Based on the telephone interviews conducted in this study, it became clear that there are utility specific drivers of declining average use per customer in addition to the common macro level drivers discussed above.

For example, in Manitoba, Manitoba Hydro is experiencing declining average use per customer due to increased market share of electric hot water heaters[28], increased market share of high efficiency gas furnaces, tighter building envelopes and higher natural gas prices.

In Quebec, higher natural gas prices, competitive advantage in the marketplace of electricity over natural gas, increases in average temperature and variations in wind velocity have contributed to declining average use per customer experienced by Gaz Métro.

For Terasen Gas, there has been a steady decline in average use per customer over time. The decline has been steeper on the mainland than on the island because gas service is newer on the island and the energy efficiency of the equipment stock on the island is therefore higher.

For PNG, a spike in natural gas prices in 2001, conservation and the use of high efficiency appliances have contributed to the declines in average use. PNG has experienced very similar declines in average use in both of the company's service territories (West and North East) despite the fact that these two regions have had very different economic fortunes in the last few years – in the West there has been a decline in wealth in the area due to the closure of facilities of local employers and the decline in the fishing industry, while in the North East the economy has been strong primarily in the oil and gas industry. This indicates that at least in the PNG service territories the local economies have not had a large impact on declining average use per customer.

In Alberta, AltaGas has experienced declining average natural gas due to newer and more efficient housing, retrofits leading to more efficient building stock, the use of more efficient appliances, the turnover of old stock, and high and volatile natural gas prices encouraging conservation.

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[28] 95% of new homes and retrofits are going to electric hot water heaters.

In Enbridge Gas Distribution's (EGD) franchise area, the utility is experiencing load loss due to the Toronto Transit Commission moving away from NGV buses, Ford no longer making Crown Victoria NGVs which are the staple of NGV taxis, and Honda not bringing any new NGVs to the Ontario market. While the company is experiencing small growth in niche markets such as residential pool heaters[29], outdoor gas fireplaces, and commercial block heaters, and the company is working on the development of new technologies such as fuel cells, these efforts are not likely to have an impact on load in the short and medium terms. As a result, these new market opportunities will have a negligible impact on declining average customer use in the foreseeable future. Similar to Manitoba Hydro, EGD is also experiencing better insulated new homes, higher natural gas prices, effects of the company's DSM initiatives and increased market share of high and mid-efficiency gas furnaces as a result of ongoing customer growth.

In Union Gas's franchise area, as previously indicated 90% of all new houses and 2/3 of replacement furnaces are going to high efficiency gas furnaces. There is some fuel switching from gas to electric hot water heating, for example, in new construction low rise apartments, 80% of the market was gas hot water, whereas today it is 60%. There is also a change in household demographics with baby boomer children leaving home, resulting in household consumption dropping. Similar to EGD, Union Gas is experiencing new markets in pool heaters and commercial block heaters, but these are small niche markets, and will therefore, have a negligible impact on declining average use per customer; the bulk of Union's load is from space and water heating.[30]

## 3.5 Conclusions

Natural gas prices and energy efficiency are common macro drivers of declining average use. Local drivers may vary due to local market conditions.

The OEE Index reveals a 1%/yr improvement in energy efficiency from 1990 to 2004. This 1% increase is in line with the 1.1% decline in natural gas use per customer in the residential sector experienced by the gas companies over the same period, and supportive of the 1.9% decline experienced in all sectors together.

[29] Enbridge Gas Distribution has 1.7 million customers; only a small percentage of customers have pool heaters.

[30] 4% of Union's customers are restaurants and only a small percentage of these have block heaters.

Based on the NRCan price forecast, high natural gas prices are likely to continue. This trend coupled with the trend toward higher efficiency gas equipment, tighter building envelopes and more pressure to achieve greater savings from DSM, means that it is likely that declines in average use will continue for the foreseeable future.

From a customer perspective, future declines in average use will likely mean that customers are using natural gas more wisely and are saving money on their gas bills. From the utility perspective, if declines in average use are not properly addressed through effective rate regulation, this could jeopardize the continued effectiveness of gas DSM, discourage utilities from promoting wise gas use and result in significant lost earnings for the utility.

There are a number of options that gas utilities can take to address the negative consequences of further declines in average use. These are discussed in Chapter 4.

# 4 Options for addressing declining average use

Achieving declines in the average use of gas per customer is not, per se, a problem. From a customer perspective, declining average use means that customers are using natural gas more wisely and saving on their gas bills. From a utility perspective, declining average use contributes to customer retention. For utilities with DSM, their DSM programs further help their customers to achieve wiser use. In fact, declining average use is the goal of DSM and of improving energy efficiency standards for heating equipment and building envelopes.

Some Canadian utilities have adopted a systems approach to DSM. This involves providing programs to ensure that the customer uses the most appropriate energy source for a given application in the most energy efficient manner, even though in certain situations, this approach could lead to fuel switching away from natural gas. A regulatory environment that enables the utility to recover all lost revenue due to declines in average use will protect the utility from earnings erosion due to the declines. Declining average use only becomes a problem for a gas distribution utility if the declines are not adequately captured in rates.

A number of options for dealing with declining average use are described in the sections below. These options include:

- Ignore declining average use
- Incorporate declining average use in the load forecast
- Revenue decoupling
- Make adjustments to fixed and variable charges
- Address declining average use per customer in a PBR environment

It should be recognized that these options are not completely distinct or independent from one another and more than one option can be operating at the same time for a particular company.

## 4.1 Ignore declining average use

One option for dealing with declining average use is to ignore it. Rate design, load forecasting, or revenue recovery would not be adjusted to reflect any decline in average use per customer. In pursuing this option, it would be prudent for a utility to continue to monitor the magnitude and impact of declining average use as well as its causation. Such information will assist the utility in designing an adjustment should one be necessary in the future.

In the short term, ignoring declining average use may be the preferred choice for a utility, either investor- or provincially-owned; if it is not posing a problem. For example, in a market that is nascent as the new infrastructure is being built based on the more recent gas use per customer data, any decline in customer usage year over year may be small and not have a significant impact on the utility's ability to recover its fixed costs in the short term. However, over time, the nascent utility will need to take declines in usage into account to protect the financial viability of the utility.

Even if the utility is not in a nascent market, but is provincially-owned, this may be an appropriate option in the short term. This type of utility is less driven by profits and is more influenced by the broader objectives of the government. However, in the medium- and long-term, the declines in use could have a major impact on revenues, and should be taken into account in rates. In addition to providing a more accurate price signal for consumers to conserve, this will ensure that the utility will be collecting revenues to adequately support its infrastructure over the long-term.

## 4.2 Incorporate declining average use in the load forecast

Traditional rate design, which is based on cost-of-service regulation, incorporates declining average use per customer in the load forecast.[31] Utilities collect payments from consumers to cover the actual cost of natural gas[32] as well as the utility's costs to deliver gas to its customers. Typically, based on the customer's rate class, the utility charges customers a fixed customer charge and a volumetric customer charge. Most of the utility's costs are recovered through the volumetric charge even though most of the costs of running a gas utility are fixed. After delivering sufficient volumes to cover all the utility's costs, the utility has

[31] Utilities determine the level of the decline in average use to be incorporated into its load forecast in utility-specific ways. For example, Terasen Gas takes into account the AGA average projected decline in average use per customer of .5%year and an annual industry poll of projected customer consumption in determining its % decline in average use.

[32] Referred to as the gas commodity, which is a pass-through cost to consumers of Canadian gas utilities.

an opportunity to earn a profit subject to its regulatory constraints. When the amount of gas delivered declines, as can happen during periods of warmer weather, economic slowdown, or when natural gas consumers become more efficient, this can affect a utility's earnings.

Declining average use can become a problem if it is not properly captured in the load forecast. To the extent that the forecast is accurate the utility and its customers are protected. In traditional rate-making the utility bears the full risk of underestimating declines in average use in the forecast and reaps the full benefits of overestimating declines. If the forecast underestimates the decline, then the utility can suffer significant losses in margin. For example, the 2005 rates approved by the Ontario Energy Board for Enbridge Gas Distribution were based on a volume forecast that included a decline in average use of 0.7%; the actual decline was 2.8% due to higher gas prices than those included in the volume forecast and resulted in a margin loss of $6.6M, with a negative after tax impact of $4.3M.[33]

A utility can mitigate its risk associated with forecasting by trying to improve the accuracy of its forecast. For example, the utility could expand its efforts to obtain better data on both short-term and long-term trends regarding customer usage; it could work with other gas utilities across Canada to share knowledge on forecasting declining average use; and could encourage its provincial government and regulator to provide province-wide annual (and perhaps quarterly) data on trends in customer usage of energy, including natural gas. Even the best forecast models will only estimate use per customer within a margin of error. This margin of error, however small, could have a major impact on a utility's earnings.

The regulator can help to mitigate the utility forecasting risk by having annual rates cases. As well, the regulator could offer the utility a risk premium on its ROE for managing the risks associated with declines in average use. However, given the uncertainty surrounding the ability to predict this risk accurately, this is not likely to be an effective tool.

Forecast risk mitigation may be difficult to achieve. Historically, forecasts were based on historical data, however, with the current market dynamics of high gas prices, government conservation programs[34] and pressure on gas utilities for more aggressive DSM, it may be difficult to reduce forecast risk associated with expected declines in use. This difficulty may be magnified the longer the period between rates cases. Moreover, a particular market could be approaching a tipping point that

[33] Tom Ladanyi, *Implications of Declining Average Use.* Enbridge Gas Distribution. 2006.

[34] For example, Ontario has just gone through a process to update its Building Code, which included strengthening provisions for increasing energy efficiency.

could lead to an acceleration of the decline and this would be difficult to predict. Therefore, improvements in forecasting and forecast risk mitigation may be insufficient to address the full impact of declining average use.

## Declining average use tracker

Improvements in forecasting and forecasting risk mitigation may be insufficient to address the risks associated with forecasting declining average use. If the level of uncertainty in predictions of declining average use results in undue risk to the utility, and this will likely be determined by the utility and its regulator on a case by case basis, then more aggressive action will be required.

A simple tracking account, a Declining Average Use Tracker, may be required that tracks variance between the forecast decline in average use and the actual decline for later disposition and true-up. True-ups would be made for both over-forecasting and under-forecasting the declines. Such an approach would eliminate the risk to the utility from the unpredictability of forecasting declining average use. This type of tracking account deals directly with, and is limited to, the risks associated with forecasting declining average use.

Where a utility faces broader revenue recovery risks from things beyond its control, a revenue tracker such as the Revenue Stabilization Adjustment Mechanism employed by Terasen Gas and Pacific North Gas, may be necessary.

## Revenue stabilization adjustment mechanism

In 1994 Terasen Gas[35] received approval from the British Columbia Utilities Commission (BCUC) to establish a revenue stabilization account called the Revenue Stabilization Adjustment Mechanism (RSAM). This mechanism mitigates the effect on its revenues of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas price volatility.

The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances between Terasen's forecast versus actual customer use throughout the year. This account reduces Terasen Gas' earnings exposure to related risks by deferring any variances between projected and actual gas consumption, and refunding or recovering those variations in rates in subsequent

[35] BC Gas changed its name to Terasen Gas Inc in 2003.

periods.[36] The RSAM account is refunded or recovered in rates as a rolling average amortized over three years.[37]

Terasen's RSAM was established in response to a series of warm winters in the early 1990's which resulted in a mismatch between Terasen Gas' forecasted revenues and actual revenues. Instead of continually arguing over the quality of the forecasts and to reduce the risks regarding earnings, Terasen Gas approached BCUC staff to introduce a mechanism that would take these variations into account.[38] The RSAM was introduced as a weather adjustment formula. Because of the difficulty in separating out revenue losses due to weather and other factors, the stabilization mechanism tracks all revenue variances from forecast. As a result, this tracker can true up variances between forecast and actual declines in average use.[39]

Prior to 1996 the RSAM was only used during the five winter months of November to March, inclusive. After 1996 it was extended to 12 months of the year resulting in Terasen Gas no longer being exposed to annual variations in revenues from its residential and commercial customers due to weather and other factors.[40]

The RSAM used by PNG was established in 2003 and is very similar to the Terasen RSAM.

### US approaches to revenue recovery risk

In the US, the focus has been on implementing mechanisms to address revenue recovery risk broadly, but at the same time address declining average use. Two main types of mechanisms are common: revenue decoupling and changes to fixed and volumetric charges. Each is discussed in subsequent sections.

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[36] Terasen Gas Inc. 2004 Annual Report.
**http://www.terasengas.com/NR/rdonlyres/eyyzlqdjvuci46fktsqah4myzijeqw6xxxtgeo2tcouz4t2ux5lucnqhyhd4z4casvzftud5kfr6zivvqpoarf3auah/Terasen+Gas+Inc+Annual+Report+2004.pdf**

[37] Jim Fraser. British Columbia Utilities Commission. Personal communication. September 7, 2006

[38] ibid.

[39]Terasen includes a declining average use adjustment in its annual load forecast. This adjustment is based on the 0.5% per year declining average use rate developed by the American Gas Association and on an annual industry poll of projected customer consumption.

[40] 1996 BC Gas Utility Ltd. Annual Report.
**http://www.terasengas.com/NR/rdonlyres/e33l5wuijpzzrnhhcupzkpzpuxcuxkedqinxiyyw3dllmambwhdep74zxdtrt3oorb73oyp36miwlwo6azy43hhygpb/BC+Gas+Utility+Inc+Annual+Report+1996.pdf**

## 4.3 Revenue decoupling

Revenue decoupling (RD)[41] is defined as a "regulatory mechanism that separates or decouples a utility's revenues from its sales of energy, in this case natural gas, and recouples revenues to some other factor, such as number of customers".[42] Revenue decoupling breaks the link between the revenues earned by gas utilities and the amount of gas they distribute. The basic approach to RD involves defining a revenue requirement and a baseline usage per customer level; over and under revenue collections from this level are placed in a deferral account for recovery in a subsequent period. RD essentially sets revenue per customer caps.[43]

There is growing interest in revenue decoupling among gas distributors particularly those that are dealing with declining average use per customer in environments with a growing customer base. The more rapid the rate of growth the larger the problem can become. New customers tend to use less gas than older customers due to newer homes having higher efficiency gas heating equipment and more energy efficient building envelopes, but the utility charges the same fixed charge, making it difficult to recover the full cost to serve the new customer in the volumetric charge.

In the US, declining average use, while a factor, is not the predominant driver of the approval of RD by regulatory utility commissions. For the most part, the key driver for public utility commissions that have approved gas utility RD is to establish a climate favourable to utility DSM to address high natural gas prices. Because of high prices, state commissions have increasingly pressured, and in some instances required, gas utilities to become more active in promoting DSM to reduce customer bills. Traditional rate structures encourage utilities to increase sales between rates cases. The RD enables the utility to recover the same level of revenues regardless of sales. RD therefore eliminates the utility disincentive to carry out DSM, however, it does not provide an incentive for DSM.

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[41] RD mechanisms have many names, including for example, Conservation Margin Tracker, Conservation-Enabling Tariff, Conservation Tariff, Margin per Customer Balancing Provision, Delivery Margin Normalization, Usage per Customer Tracker, Customer Utilization Tracker.

[42] Joelle R. Stewart. Staff of Washington Utilities and Transportation Commission. *Natural Gas Decoupling, Rate Spread and Rate Design*. Testimony before the Washington Utilities and Transportation Commission. Docket No. UG-060256. Exhibit No. T(JRS-1T). August 15, 2006.

[43] Revenue decoupling can involve either a fixed revenue per customer cap with a true-up mechanism for variances between forecast and actual revenues, or revenue indexing. Revenue indexing decoupling is usually referred to as revenue indexing PBR. This latter definition of revenue indexing as a form of PBR has been adopted in this report rather than as an RD mechanism. See section 3.5 for further discussion of revenue indexing PBR.

RD reduces a utility's risk from under recovering revenues and therefore generates more stable revenues, cash flows and earnings. RD helps customers to the extent they are able to participate in any DSM the utility provides. Because of the reduced risk, utilities may suffer a reduced return on equity by the regulator as a condition of approval of the RD. Opponents of RD in the US argue that RD is too blunt a tool to deal with rate adjustments for revenue losses. They believe that it is important to determine the reasons for the decline in sales and make adjustments accordingly.

As of early 2006, several gas utilities had filed RD proposals in New York, Ohio, Utah and Washington.[44] Not all applications for RD are being approved by PUCs. Southwest Gas in Arizona, for example, proposed an RD for residential customers that would track in a balancing account the actual margin each month per customer versus the authorized level per customer and proposed a US $4M DSM program through a surcharge on customer bills, however the proposal did not receive support from commission staff, the consumer advocate's office and other stakeholders.[45] As well, in January 2006, the Connecticut Department of Public Utility Control rejected RD in the form of sales and per customer adjustments because of the shift of business risk from the utility to the customer.[46]

At least seven gas utilities in the US (Baltimore Gas and Electric, Cascade Natural Gas, Northwest Natural Gas, Southwest Gas, and Piedmont Natural Gas, Washington Gas Light) have received approval from their regulators for RD. Each utility and its RD is discussed below.

### Baltimore Gas and Electric and Washington Gas Light

In 1998 Baltimore Gas and Electric received approval for an RD mechanism, referred to as a Monthly Rate Adjustment to be applied to residential and general service customers. In 2005 Washington Gas Light received approval for a similar RD. Both mechanisms are based on a revenue per customer cap and a monthly true-up.

Under this regime volumetric charges are adjusted to keep the revenue growth per customer the same. This adjustment takes place each month and is determined using test year data. The first step in making the rate

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[44] Ken Costello. Briefing Paper: Revenue Decoupling for Natural Gas Utilities. National Regulatory Research Institute, April 2006: 18, 23. p4

[45] American Gas. December 2005/January 2006. p.25

[46] Ken Costello. Briefing Paper: Revenue Decoupling for Natural Gas Utilities. National Regulatory Research Institute, April 2006: 18, 23. p5

adjustments is to determine the change in the number of customers, which is determined by subtracting a test year number of customers from the actual current month number of customers. This change in the number of customers is then used to calculate the change in allowed revenues by summing the customer charge impact and the volumetric charge impact.[47]

The change in allowed revenues is then added to a test year base revenue and from this the actual base rate revenue is subtracted to determine the required revenue adjustment. This required revenue adjustment is then added to the variance account and recovered through volumetric charges. These calculations are done separately for the residential and general service customers. This decoupling does not normalize the data used for weather.

### NW Natural

In November 2000 the price of natural gas in Oregon began to escalate and there were public appeals by the governor to conserve. The price shock coupled with these pleas led to a reduction in natural gas consumption per residential customer of almost 10%.[48] As consumption dropped, earnings dropped and this spurred NW Natural to request an RD from the Public Utility Commission (PUC).

In September 2002, the PUC of Oregon approved an RD, referred to as the Distribution Margin Normalization, "so that the utility can assist its customers with energy efficiency without conflict."[49] As part of the approval, NW Natural committed to promoting energy conservation and is required to collect from all of its residential and commercial customers a surcharge of 1.5% of total monthly bills which are passed on to the Energy Trust of Oregon to implement DSM programs.

NW Natural's RD consists of two components: a price elasticity factor that adjusts for increases and decreases in consumption of residential and commercial customer groups due to changes in commodity costs or periodic changes in the company's general rates; and an adjustment calculated monthly based on differences in volumes between forecast

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[47] *Customer Charge Impact* = change in the number of customers x current customer charge. *Volumetric Charge Impact* = change in the number of customers x test year average use per customer x system charge per therm.

[48] American Gas Association" Frequently Asked Questions About Energy Efficiency and Innovative State Reform".

[49] This RD was in place until August 2005, when it was modified by the Oregon PUC to allow for 100% amortization of margin differentials instead of the 90% allowed in the 2002 approval. American Gas Association. Natural Gas Rate Round-Up Decoupling Mechanisms – 2006 Update. p.3.

and actual for residential and commercial customer groups. NW Natural has a separate mechanism to adjust for weather, its weather-adjusted rate mechanism (WARM) for all residential and commercial customers, which is approved until 2008.

A 2005 study conducted for NW Natural indicates that its RD mechanism has had a positive impact on the company. It reduced the utility's business and financial risks without reducing service quality. The company shifted its focus from marketing to promoting energy conservation; the utility's DSM through the Energy Trust has had a statistically insignificant effect on use per customer.[50]

### Southwest Gas Co.

In 2004 the California Public Utilities Commission approved a RD mechanism for residential and master-metered customers of Southwest Gas. Under this regime volumetric charges are adjusted to keep the revenue growth per customer the same. In order to determine the required revenue adjustment each month, monthly baseline volumes of gas for a test year are multiplied by authorized volumetric charges for each customer type (e.g. residential, master-metered). The product of this is then subtracted from the actual revenues generated from these customers, which is then subsequently divided by the actual volume of gas for each customer type to give the revenue adjustment required. This required revenue adjustment is then added to a variance account and recovered from customers through volumetric charges.

### Piedmont Natural Gas

In November 2005, the North Carolina Utilities Commission approved a Customer Utilization Tracker (CUT) mechanism for Piedmont Natural Gas as an experimental rate for three years, to November 1, 2008. In its decision the PUC indicated that the CUT would give the utility a conservation incentive to assist residential and commercial customers, while reducing the shareholder risk and the frequency of future rates cases.[51] During the life of the CUT, the utility is required to contribute $500,000 per year toward conservation programs and to develop effective conservation programs to submit to the PUC for approval and annual review.[52] The CUT has a more explicit adjustment for weather

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[50] Christensen Associates. A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural. March 31, 2005.

[51] North Carolina Utilities Commission. Order Approving Partial Rate Increase and Requiring Conservation Initiative, Docket Nos. G-9, Sub 499; G-21, Sub 461;G-44 Sub 15. November3, 2005.p.24.

[52] *ibid*. p.8. As part of the approval, the PUC terminated the Weather Normalization Adjustment Mechanism. Ibid. p.8.

than similar RD mechanisms and is applied separately to residential, and small and medium general service customers. To determine the change in volumetric charges that will keep the revenue growth per customer the same and will take into account the impacts of weather, Piedmont produces a normalized measure of volume that is the sum of base load volumes and heat sensitive volumes.[53] The revenue adjustment required is then calculated by taking the normalized measure of volume and subtracting the actual volume and then multiplying the result by the existing volumetric charge per volume.

### Cascade Natural Gas

In April 2006, Cascade Gas received approval for a RD for residential and commercial customers from the Oregon PUC. The RD is comprised of two deferral accounts: one that tracks monthly deviations in gas use from normal weather consumption and the other that tracks monthly deviations from non-weather related changes in customer gas use. The accounts will be amortized over the next year as increments to the commodity charge. The utility RD also includes a 0.75% of revenue contribution of the company to fund customer DSM, certain service quality requirements and a penalty for failing to meet targets for addressing customer complaints. The RD remains in effect until September 2010.

## RD and declining average use per customer

Revenue decoupling breaks the link between the revenues earned by gas utilities and the amount of gas they distribute, thereby eliminating the need to recover a certain level of revenues from volumes. Rates would be set based on establishing a per customer revenue cap, and underages and overages from the cap would be trued up. However, there would still be risk associated with setting the appropriate revenue level per customer based on the forecast of decline in average use. To eliminate this risk, a Declining Average Use Tracker would be needed.

A RD is a blunt instrument that eliminates risks associated with revenue recovery related to sales. It is too blunt an instrument if the sole purpose is to address declining average use. Unless, a utility is experiencing other revenue loss risk factors in addition to declining average use (e.g. weather risks, debt recovery, infrastructure renewal) resulting in undue risk or there are other policy reasons for choosing RD, RD may not be appropriate.

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[53] *Base load volumes* = actual number of customers x base load sales.
*Heat sensitive volumes* = actual number of customers x heat sensitivity factors x normal degree days.

In the US declining average use, while a factor, is not the predominant driver of the approval of RD by regulatory utility commissions. For the most part, the key driver for PUCs that have approved gas utility RD is to establish a climate favourable to utility DSM to address high natural gas prices. RD eliminates the utility disincentive for DSM as the utility's revenue is decoupled from the level of sales. The utility is protected from losses in margin for reducing gas use per account.

For Canadian gas utilities with well developed DSM portfolios, effective tools to allow for recovery of revenue losses due to DSM and incentives that achieve aggressive DSM, such decoupling mechanisms may be overkill if the sole purpose of the mechanism is to promote DSM. With increased government pressure to reduce customer gas bills, there may be renewed interest in RD in jurisdictions that carry out regulated DSM. For Canadian utilities that are considering entry into regulated DSM, it may be appropriate to start with RD to eliminate any DSM disincentive.

## *4.4 Make adjustments to fixed and variable charges*

Depending on the level of the decline in average use per customer, how quickly the utility customer base is growing and other factors, it may become harder for the utility to recover its costs in the volumetric charge. In addition to the options previously discussed, this problem can be addressed by altering the rate design to recover more of the utility's fixed costs in the fixed customer charge. An extreme version of this option is to eliminate the volumetric charge. This type of rate-setting is common in the cable and telephone industries, with monthly fixed fees for service. The AGA refers to this total fixed charge option as 'straight fixed variable rate design.[54]

Four examples of rate designs employed by US gas utilities that try to do a better matching of the utility's fixed costs with its fixed customer charges are discussed below. The four utilities are: Laclede Gas, Oklahoma Natural Gas, Atlanta Gas Light and Excel Energy.

### Laclede Gas

Laclede Gas in Missouri has developed a rate structure for its residential customers that includes an infrastructure replacement charge and seasonal rates for volumes. The customer service charge for residential customers is a fixed cost, which includes an infrastructure system

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[54] The AGA Glossary defines straight fixed variable rate design as a method of determining demand and commodity rates whereby all costs classified as fixed are assigned to the demand component AGA. AGA Glossary.
**http://www.aga.org/Content/NavigationMenu/About_Natural_Gas_Glossary?Natural_Gas_Glossary_(R).htm**

replacement surcharge. The charge for gas used consists of a charge for the delivery or distribution of the gas, plus a charge, known as the Purchased Gas Adjustment (PGA) charge that reflects Laclede's cost of gas purchased from various suppliers. Volume charges are seasonal and with a declining block structure, with summer rates cheaper than winter rates.[55]

### Oklahoma Natural Gas

Oklahoma Natural Gas, a subsidiary of ONEOK, provides its customers with a choice in the rate plan they select. Customers can either choose a rate plan with a high fixed (demand) rate and a low variable (delivery) charge or a low fixed rate and high delivery charge. For example, Rate Plan A contains a monthly service charge of US$9 and a delivery charge per dekatherm[56] of $1.9967, while Rate Plan B offers customers a monthly service charge of $20 and a delivery charge per dekatherm of $0.2367.[57]

### Atlanta Gas Light

Atlanta Gas Light (AGL) charges its residential and commercial customers a fixed base rate to recover the utility's cost of delivering the gas, maintaining the delivery infrastructure and reading the meter. The base rate charge - called the Dedicated Design Day Capacity Charge (DDDC) - is a fixed charge but is unique to each customer. The DDDC is calculated based on how much gas a customer uses during the coldest period of the year to ensure that AGL has enough capacity to meet all customer needs in cold weather and to allocate the customer's share of the cost on the delivery system. The DDDC charged to each customer will vary based on the size of the home and the number and types of the appliances and equipment used. The DDDC charge is recalculated annually for each customer and is based on the consumption in the previous year.[58]

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[55] Laclede Gas website. **http://www.lacledegas.com/customer/rrsummary.htm.** Accessed September **7**, 2006.

[56] A dekatherm is a measurement of energy content. One dekatherm is the approximate energy content of 1,000 cubic feet of natural gas.

[57] ONEOK website. **http://www.oneok.com/ong/customerservice/rateinfo/ong_understand_bill.jsp.** Accessed September 7, 2006.

[58] Atlanta Gas Light website. **http://www.aglc.com/RatesRegulations/CustomerCharges.aspx.** Accessed September 7, 2006.

### Xcel Energy

In response to a trend of declining average use per residential customer of 2% per year, the North Dakota Public Service Utility Commission approved in 2005 a straight fixed variable rate for Xcel Energy's residential customers. There was little public opposition to this approach as it resulted in a 1% rate base increase, compared with previous rate base increases of 15% to 30%, because of changes in wholesale gas costs.[59]

## Adjustments to fixed/volumetric charges and declining average use per customer

In theory, improvements to rate design that lead to a one to one match of fixed costs with fixed charges and variable costs with variable charges are preferred. In the case of the gas distribution industry this would mean that most costs would be embedded in the fixed charge.

In practice, however, this may be difficult to achieve due to customer opposition to increases in fixed charges. Raising fixed charges would have the greatest impact on low volume customers such as residential and small commercial customers and low-income customers, in particular. Placing a greater financial burden on low-income customers is likely to meet with significant opposition.

In jurisdictions such as Manitoba[60] where electricity prices are low and on par with gas prices, a slight increase in fixed gas charges for Manitoba Hydro's residential customers could be the tipping point for large scale fuel switching to electricity for heating needs. In Quebec for Gaz Métro, a similar situation of fuel switching could occur due to the competitiveness of electricity prices compared with those of natural gas. Even in jurisdictions with more competitive gas prices compared with electricity prices, such as Ontario, increasing fixed charges may be unwelcome with customers to varying degrees depending on the franchise area.

Unless the rate design went to a rate based solely on fixed charges – a straight variable rate design – adjustments to fixed and volume charges would leave the utility exposed to revenue recovery risks due to declining average use from the remaining volumetric portion in rates.

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[59] *American Gas*. December 2005-January 2006. p.24.

[60] Manitoba Hydro has a small fixed charge for residential customers of $10/customer. With the larger customers (150 out of 260,000 are large customers), there is a better rate structure leading to more revenue stability.

However, even with a straight variable rate design, the utility would still be exposed to the risk associated with forecasting the declines in average use to be recovered in the fixed charge. An additional mechanism, such as a Declining Average Use Tracker, would be required to fully address this risk. Therefore, it is suggested as a matter of good rate design, rather than to deal with declining average use, to move incrementally and carefully to the extent reasonable for a particular utility and its market toward a better matching of fixed costs with fixed charges.

## *4.5 Address declining average use per customer in a PBR environment*

### Types of PBR

There are two main types of regulation that North America gas utilities are operating under: cost-of-service regulation (COS) and performance based regulation (PBR). PBR is a rule-based approach that is seen as an alternative to COS as it requires less regulatory oversight and relies less on the discretion of regulators. In PBR, rules are created to provide inherent incentives for utilities to achieve regulatory objectives and to try minimize the risks to the utilities and its customers.

PBR goes by a variety of names, depending on the jurisdiction, these include: alternative regulation, incentive regulation, and formula rate plans. For the purposes of this report this rule-based approach will be referred to as PBR. Within PBR there are a number of options for setting the PBR rules; these include:

- **Deemed caps or freezes** – a variable, such as price, revenue or revenue per customer is fixed for a specific period of time. In North America, these deemed caps are most commonly placed on price. An example of a deemed price cap would be customer rates being capped or frozen over the duration of a 5 year plan.

- **Indexed caps** – caps a utility's prices or revenues using a formula. This formula, called the Price Cap Index (PCI) or Revenue Cap Index (RCI), depending on which variable is being capped, restricts the growth in allowed prices or revenues so that the growth must be less than or equal to the growth in the PCI or RCI. This is the most common form of PBR worldwide.

- **Earning sharing mechanisms**[61] – adjust rates automatically for differences between the company's actual and target rate of return, most commonly return on equity (ROE). If the utility exceeds the target ROE then the surplus revenues are shared with its customers. Alternatively, if the utility does not meet its target, then the customers share the revenue shortfall. The percentage of the surplus or shortfall shared with customers can vary, but commonly the split is even at 50/50, with 50% going to the customer and 50% to the utility.

### PBR and declining average use per customer

The formula for the indexed cap for both RCI and PCI is the same: the growth in the indexed price cap index or revenue cap index is equal to an external inflation measure (P) minus a productivity factor (X) plus any factors outside the company's control (Z).[62] In a RCI PBR or in earnings sharing PBR, rates are adjusted to ensure a specified level of revenue recovery. Within this process, adjustments to rates can be made which capture declining average use. Depending on the size of the variances incurred between adjustments, the utility, may wish to create a Declining Average Use Tracker to adjust for variations between forecasted and actual declines in average use.

In a PCI PBR environment[63] rates are capped and the actual revenues are determined based on the cap set. There is no adjustment made if the utility over- or under-earns. This type of rate setting, in its purest form, does not require a volume forecast and therefore, provides no

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[61] Teresan Gas operates under an Earning Sharing Mechanism PBR which adjusts rates automatically for differences between the company's actual and target return on equity (ROE). If Terasen exceeds its target ROE, then the surplus revenues are shared with its customers; alternatively, if the utility does not meet its target then the customers share the revenue shortfall. The split of the surplus or shortfall shared with customers is 50:50 (e.g. Terasen will retain 50% of its above target revenues and its customers will receive the corresponding above target savings). If Terasen meets its ROE target, then it retains 100% of the earnings.

[62] Growth in PCI/RCI = P – X + Z
P is equal to the growth in an external inflation measure which can be economy-wide, industry-specific or for a peer group.
X is the X-factor which slows rate of revenue growth and which in North America is based on external industry productivity and input price information.
Z is the Z-factor which adjusts the PCI/RCI growth for external developments outside the company's control. Common Z factors include changes in government policy, change in industry accounting standards and natural disasters.

[63] Union Gas and Enbridge Gas Distribution may face a price cap PBR in 2008. Gaz Métro currently has a hybrid PBR that involves a price cap and a cost-of-service component. The cost-of-service revenue requirement (RR) is compared to a theoretical price cap. If the RR is less than the price cap, then the utility shares this productivity with its customers, 25% for the company and 75% for its customers; if the RR is greater than the price cap then the RR is raised to the price cap level. Because a load forecast is required each year the utility files a rates case, declining average use can be incorporated into the load forecast.

opportunity to make adjustment for declines in customer use over the PBR period. To correct for this problem, an adjustment to rates to account for declines in average use must be added.

Three alternatives for making this adjustment to rates in a PCI PBR environment have been identified. One alternative would be to include a declining average use factor in the calculation of the price cap.[64] A second alternative is to adjust the X-factor in determining price to account for declining average use.[65] A third alternative would be to make declining average use a Z factor and accumulate differences between the forecast decline in average use and the actual decline in average use in a tracker for later disposition. In general, making declining average use a Z factor may be less attractive to regulators than the other alternatives, as regulators try to minimize the number of Z factors. The alternative adopted should be tailored to the specific circumstances of the utility.

## 4.6 Conclusions

There are a number of options for addressing declining average use per customer in Canadian gas utilities. Five options were discussed above; ignore declining average use, incorporate declining average use in the load forecast, decouple revenue from gas use, make adjustments to fixed and volumetric charges and address decoupling in PBR. Some of these options have been shown to be more appropriate than others and which option a utility adopts to address declining average use per customer should be tailored to the market conditions and the regulatory environment in which the utility operates.

It should be recognized that the options presented for addressing declining average use are not completely distinct or independent from one another and more than one option can be operating at the same time for a particular company.

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[64] New rate = old rate (1 + P + decline in average use – X) + Z factors.

[65] New rate = old rate [1 + P – X (declining average use adjustment factor)] + Z factors.

# Conclusions and recommendations

Canadian natural gas utilities have been experiencing a steady trend of declining natural gas use per customer, corresponds roughly to a decline in average use of 1.9% per year for all sectors and in the residential sector specifically, of 1.1% per year. The Canadian decline in residential average use is consistent with US experience in the residential sector, with the US decline averaging about 1% per year.

The analysis of the Canadian situation has revealed that changes in number of customers and climatic variation are not the main drivers of declining average use. As numbers of customers have continually increased and climatic temperature variation has been shown to have, in general, a very minor effect on natural gas use change, other factors must be driving the decline.

## Contributing factors to declining average use in Canada

Over time Canadian homes and businesses have become more energy efficient. Over the last ten years, it is this market trend that is likely to have been the most significant common driver for declines in average use. The OEE Index reveals a 1%/yr improvement in energy efficiency from 1990 to 2004. This 1% increase is in line with the decline in natural gas use per customer in the residential sector experienced by the gas companies over the same period, and is supportive of the 1.9% decline in all sectors together.

Based on the NRCan price forecast, high natural gas prices are likely to continue. This trend coupled with the trend toward higher efficiency gas equipment, tighter building envelopes and more pressure to achieve greater savings from DSM, means that it is likely that declines in average use will continue for the foreseeable future.

We may be moving into a different era. In the past, historical experience was a good predictor of the gas market in the future. Today, it may not be as reliable due to short to medium term supply shortages in natural gas, restructuring in the Canadian economy due to a high Canadian dollar in relation to the US dollar, greater consumer awareness of energy efficiency and government pressure on gas utilities and others to assist customers to reduce gas usage and bills. These factors could bring us to the tipping point of an accelerated declining average use.

## Implications of declining average use for utilities and their customers

From a customer perspective, future declines in average use will likely mean that customers are using natural gas more wisely and are saving money on their gas bills. From a utility perspective, declining average use contributes to customer retention. This keeps natural gas competitive with alternative fuels. For utilities with DSM, their DSM programs will further help their customers to achieve wiser use.

A regulatory environment that enables the utility to recover all lost revenue due to declines in average use will protect the utility from earnings erosion due to the declines. Declining average use only becomes a problem for a gas utility if the declines are not adequately captured in rates.

Utilities, such as ATCO Gas, AltaGas ,Enbridge Gas Distribution and Union Gas, with the highest percentages of residential gas customers in markets where natural gas is the predominant residential fuel, have the largest potential impact on profitability because of any declining average use per customer in this sector.

## How to address declining average use

The utility response to declining average use per customer should be tailored to the market conditions and the regulatory environment in which the utility operates. These conditions differ across the country and among the individual utilities.

There are a number of options for addressing declining average use per customer in Canadian gas utilities. Five options are discussed in this paper; ignore declining average use, incorporate declining average use in the load forecast, decouple revenue from gas use, make adjustments to fixed and volumetric charges and address decoupling in PBR. These options are not completely distinct or independent from one another and more than one option can be operating at the same time for a particular company.

### Ignore declining average use

One option for dealing with declining average use is to ignore it. In the short term, ignoring declining average use may be the preferred choice for a utility, either investor- or provincially-owned; if it is not posing a problem. However, over time, a utility will need to take declines in usage into account to protect the financial viability of the utility.

## Incorporate declining average use in the load forecast

The most effective method of mitigating the effects of declining average use is through an offsetting increase in margin per unit rate. This can be accomplished through effective rate-setting either in cost-of-service or under PBR. The effectiveness of the methods will be largely dependent on the accuracy of the load forecast.

Should experience reveal that forecasts of declining average use are so unreliable that they result in significant margin erosion between offsetting adjustments, it may be necessary to track variances in an account, with true-ups made for under- and over-forecasting of the declines. A simple tracking account, a Declining Average Use Tracker, could be established which would track variance between the forecast decline in average use and the actual decline for later disposition and true-up.

## Revenue decoupling

Revenue decoupling breaks the link between the revenues earned by gas utilities and the amount of gas they distribute, thereby eliminating the need to recover a certain level of revenues from volumes. Rates would be set based on establishing a per customer revenue cap, and underages and overages from the cap would be trued up. However, there would still be risk associated with setting the appropriate revenue level per customer based on the forecast of decline in average use. To eliminate this risk, a Declining Average Use Tracker would be needed.

For Canadian gas utilities with well developed DSM portfolios, effective tools to allow for recovery of revenue losses due to DSM and incentives that achieve aggressive DSM, such decoupling mechanisms may be overkill if the sole purpose of the mechanism is to promote DSM. With increased government pressure to reduce customer gas bills, there may be renewed interest in RD in jurisdictions that carry out regulated DSM to create a more favourable climate for DSM. RD eliminates the utility disincentive for DSM as the utility's revenue is decoupled from the level of sales. The utility is protected from losses in margin from reducing gas use per account.

For Canadian utilities that are considering entry into regulated DSM, it may be appropriate to start with RD to eliminate any DSM disincentive.

## Adjustments to fixed and variable rate charges

Making adjustments to rate design to increase the amount of revenue recovered through fixed charges can address risk associated with declining average use to varying degrees. Unless the rate design went to a rate based solely on fixed charges - a straight variable rate design -

adjustments to fixed and volume charges would leave the utility exposed to revenue recovery risks due to declining average use from the remaining volumetric portion in rates. However, even with a straight variable rate design, the utility would still be exposed to the risk associated with forecasting the declines in average use to be recovered in the fixed charge. An additional mechanism, such as a Declining Average Use Tracker, would be required to fully address this risk. Therefore, it is suggested as a matter of good rate design, rather than to deal with declining average use, to move incrementally and carefully to the extent reasonable for a particular utility and its market toward a better matching of fixed costs with fixed charges.

### Addressing declining average use per customer in PBR

In a RCI PBR or in earnings sharing PBR, rates are adjusted to ensure a specified level of revenue recovery. Within this process, adjustments to rates can be made which capture declining average use. Depending on the size of the variances incurred between adjustments, the utility, may wish to create a Declining Average Use Tracker to adjust for variations between forecast and actual declines in average use.

In a PCI PBR environment rates are capped and the actual revenues are determined based on the cap set. There is no adjustment made if the utility over- or under-earns. This type of rate setting, in its purest form, does not require a load forecast and therefore, provides no opportunity to make adjustment for declines in customer use over the PBR period. To correct for this problem, an adjustment to rates to account for declines in average use must be added.

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