Atlantic Institute for AIMS Market Studies

HAVING OUR GAS AND SELLING IT TOO:

NATURAL GAS DISTRIBUTION IN ATLANTIC CANADA

THOMAS L. TUCKER, Ph.D.

The AIMS Oil and Gas Papers (PAPER #3)

Brian Lee Crowley, Series Editor

February 2002

Atlantic Institute for Market Studies

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CONTENTS

Foreword iv

Executive Summary v

About the Author vii

Introduction 1

The Gas Industry in Context 3

Why Regulate? 12

Economics of Gas Transmission and Distribution 16

Market Economics 21

What's Happening in Atlantic Canada? 24

Recommended Regulatory Regimes and Policies 28

Appendix 1: The Impact of Industrial Bypass Agreements 32

Bibliography 34

FOREWORD

One of the biggest challenges facing policy makers can be widespread beliefs in the public mind about "the way things ought to be," beliefs that do not stand up to analysis, but which prove remarkably hard to dislodge. Because governments are sensitive to public opinion, these common perceptions, even though mistaken, can still shape public policy, often for the worse.

A classic example is to be found in frequently encountered attitudes toward the region's newly emerging natural gas industry. The purpose of this fine paper by Dr. Tom Tucker, is to meet head on some of the most common attitudes toward this new industry, and to subject them to the light of experience gathered elsewhere in Canada and internationally.

Under Dr. Tucker's policy microscope, beliefs such as that we should sell our gas to ourselves cheaply, while charging a premium to consumers in New England, are shown to be totally fallacious. So too is the cherished notion that the greatest benefit to this region from natural gas would come from keeping and using as much of it as we possibly can here, while keeping exports relatively low. Subsidizing local gas distribution as an economic development strategy is equally shown to be a hollow goal. The paper clearly shows that the alternative — deregulating the distribution industry while realizing the full market value of the gas for its owners (the citizenry) — will bring the greatest benefits to the region.

This third paper in our *Oil and Gas Series* is thus a worthy addition to *Atlantic Petroleum Royalties: Fair Deal or Raw Deal?* by Dr. G. Campbell Watkins and *Taking Off the Shackles: Equalization and the Development of Nonrenewable Resources in Atlantic Canada* by Kenneth J. Boessenkool. These papers, both of which are available on our web site, established that, on the one hand, the offshore royalty regime in the region stands up well to comparison with equivalent regimes in other parts of the world, and that, on the other hand, Ottawa's treatment of provincial natural resource revenues under equalization represents a confiscation of one of the region's chief capital endowments. Watch for more such insightful and far-sighted papers on the future of this important industry over the course of the coming year.

Brian Lee Crowley, President
Atlantic Institute for Market Studies
Editor of *The AIMS Oil and Gas Papers*

Executive Summary

Natural gas is emerging as perhaps the single largest economic opportunity in living memory for both Nova Scotia and New Brunswick. Have our governments got things right regarding access to gas? The answer to this question is crucial in determining if Atlantic Canadians are to get the best value from the availability of natural gas.

With the beginning of gas production from the Sable Offshore Energy Project, Atlantic Canadians have the opportunity to add gas to their energy mix. But blindly copying a regulatory and policy framework from other jurisdictions across Canada, where the gas market is mature, may not be the wisest approach. While gas markets elsewhere are mature and the gas industry is a major player, here in Atlantic Canada natural gas has a virtually zero market share. The distribution infrastructure is either new or still on the drawing board, and gas must compete against well-entrenched electrical utilities and fuel oil suppliers.

So what do we know, and what should be done, about gas distribution in this region?

1. Too often, people see the consumption of gas in Atlantic Canada as a benefit and the shipping of gas to the United States as exploitation. We must realize that even if every home and business in Atlantic Canada were to burn gas, the volume would not be sufficient to justify the production, transmission, and distribution infrastructure costs. This leads to two conclusions: first, selling our natural gas to the United States is a condition of our own access to the resource; and second, the demarcation line between benefits and exploitation is not whether we *consume* it, but rather how we maximize the economic returns to Atlantic Canadians from the gas sector as a whole.

2. Competitive forces are ultimately the best determinant of where and to whom gas is delivered, and they will help lead to the most efficient pricing and allocation of gas as well as other energy sources. Foisting artificial gas distribution targets on local distribution companies (LDCs) regardless of the economics might seem politically attractive, but, as Nova Scotia has finally come to realize, artificial targets ultimately lead to market distortions that destroy potential benefits for the region.

3. To build a gas market, LDCs need to win market share by encouraging consumers to switch from existing fuels. The spread in price between delivered gas and close substitutes is one critical determinant; another is the cost of replacing fuel-oil-burning, electrical, or wood-burning equipment with gas appliances. The level of discounting in the delivered price of gas should be determined by LDCs, not by regulators. It is in the LDCs' best interest to build markets as quickly as possible.

4. Industrial bypass agreements, which allow transmission companies to sell gas directly to large industrial users, should be approved only when such clients would not otherwise use gas, or where building

lateral lines to connect these high volume users provides access to other customers who would not otherwise be served by gas. Therefore, industrial bypass agreements should be considered only under exceptional circumstances.

5. The industry is in its infancy. It has no ability to control the market or exercise monopoly power. Therefore the best inaugural regulatory framework for a distribution system is to choose an LDC and allow it to develop a distribution system. The second best option would be a regulatory regime to approve and monitor a cost/pricing model. The most appropriate regulatory framework today would not be the best one in the future as the industry matures. Therefore, we need to be dynamic and flexible in our approach to regulation. A cost of service model with a guaranteed return on capital appears to be the most appropriate for launching the industry. As the industry builds market share and amortizes infrastructure costs, and as the cost of service declines, the regulatory framework should evolve into a performance-based model – that is, one that encourages maximum efficiency and squeezes out excess profits. Adopting a flexible regulatory framework that recognizes both the needs of the industry as it evolves and the interests of customers is crucial.

6. Unbundling of services (i.e., separating the marketing, billing, and distribution of natural gas) is not appropriate for a greenfield market; unbundling has slowed the distribution of gas in New Brunswick.

The recommended regulatory model and accompanying policies, by harnessing competition and market discipline, will help ensure that the maximum number of Atlantic Canadians have access to natural gas at the lowest possible cost. However, competitive forces cannot guarantee that the gas market will grow rapidly – only that it will grow efficiently. Therefore, to avoid artificially encouraging rapid access, governments will have to resist politicizing the regulatory process.

About the Author

Dr. Tucker holds a BS, MS and Ph.D from Michigan State University and an MBA from Lake Superior State University. He has extensive experience in the areas of government policy analysis and development, industrial development and benefits, strategic and operational planning, economic analysis and forecasting, business planning and assessment, program evaluation and teaching at the university level.

Prior to joining AIMS he worked at Saint Mary's University as their Manager, External Program, developing, marketing and delivering new for-profit executive and management development training/seminars at the University. He has recently worked for the Nova Scotia Petroleum Directorate as their Director of Benefits & Training and he has held Director General and other senior management positions with the federal government across Canada. Dr. Tucker has a strong interest in resource economics with a particular emphasis on oil and gas and forest resource. He also has a strong interest in fiscal and monetary policy and its impact upon the economy.

INTRODUCTION

For more than 40 years, Maritimers have been embarking on a journey toward prosperity driven by offshore natural gas.[1] In keeping with the prospector's optimism, they have dreamt of striking it rich and all that that could mean. Given the large proven and potential reserves of offshore natural gas, plus the commissioning of the inaugural infrastructure to bring gas to markets, most Maritimers now expect the dream to become a reality, and soon.

The events of September 11, 2001, are expected to intensify interest in Atlantic Canada's petroleum resources. We are now seeing a renewed interest in decreasing dependence on Middle Eastern oil, as well as discussions of a continental energy policy with greater self-sufficiency as its goal. We also see evidence that multinational oil and gas producers active in North America are looking more seriously at the Atlantic Canadian offshore. One indication of that interest is the level of recent bids for parcels on the Scotian Shelf ($527 million in total): two bids were in excess of $170 million, one being more than twice any previous bid.[2] These are indeed exciting times.

Given today's energy market, the state of the economy, and the international environment, the principal question for this paper is, What would be the best regulatory and policy framework for natural gas distribution in Atlantic Canada? "Best" is defined in terms of providing natural gas to the maximum number of consumers at the lowest price. Although the availability of natural gas for consumption may be the most visible local result of the industry, it is not the only benefit – nor is it likely to be the most significant. It should also not be the sole determinant to gauge whether we are truly benefiting from natural gas developments or merely being exploited.

How do we maximize the benefits from the availability of natural gas for Atlantic Canadians? Why don't we just keep *our* gas here and not sell it to Americans? Or, to put it another way, why are we selling our natural resources to the United States at all when we should be using them here? Or, why don't we sell our gas really cheaply to ourselves and at a premium to US consumers? Why not require local distribution companies (LDCs) to provide access for the majority of Atlantic Canadians to the gas distribution network, regardless of the economics, as the quid pro quo for having a franchise? After all, aren't communities that don't have access to gas at an economic disadvantage relative to those that do? That

[1] Newfoundland and Labrador is not included in this analysis because its primary petroleum resource is oil. However, the availability and distribution of natural gas from the Scotian Shelf has the potential to impact all of Atlantic Canada, including Newfoundland and Labrador and Prince Edward Island. The regulatory and policy framework recommended in this paper will therefore apply to Newfoundland and Labrador and Prince Edward Island as well as to Nova Scotia and New Brunswick. Hence, the paper makes reference both to the Maritimes (with respect to the production and current use of natural gas) and to Atlantic Canada (to include the provinces that could eventually benefit from natural gas distribution).

[2] The approval of these bids is currently under consideration by the Canada–Nova Scotia Offshore Petroleum Board.

is, doesn't gas bring in new industries? Answers to these questions are at the heart of determining the best regulatory and policy framework for gas distribution in Atlantic Canada.

Before we can intelligently deal with these questions, though, we need to know something about the characteristics of the North American industry, its history, how the industry operates today, and how Atlantic Canada fits in. Therefore, I will first set the stage by providing a brief overview of the industry, including its history in Canada, and I will discuss the evolution of the natural gas industry from a shut-in market to a continental market. I will also look at how natural gas gets from the wellhead to the customer. With this as a background we can begin to answer the questions. Then we will look at why (and whether) regulations are needed and the types of regulatory models characteristic of the industry. Finally, I will propose a regulatory and policy framework in which we can optimize the potential benefits from natural gas distribution for Atlantic Canadians.

The Gas Industry in Context

To make an informed judgment as to the best regulatory framework for gas distribution in Atlantic Canada, we need a clear understanding of the industry, its components, and how it operates. Where do we find natural gas? What are its components? What form does the industry take, and why? And how does the market for natural gas work?

Natural gas that pressurizes oil formations and is dissolved in oil is called *associated* gas. It is a by-product of oil production and was seen historically as a waste product. The primary interest and focus of producers was on discovering oil. When they found free-standing gas (gas not associated with oil deposits), as is common in the Nova Scotia offshore, they capped the wells, leaving the gas in the ground.

What is Natural Gas?

Natural gas at the wellhead is not a homogeneous product. It contains a number of by-products and waste products that vary from well to well and from field to field. Raw gas is converted to market gas at gas processing plants, which strip out natural gas liquids (propane, butane, ethane, and other heavier hydrocarbons), hydrogen sulfide, carbon dioxide, nitrogen, helium, and water. Natural gas liquids (NGL) from the gas stream can be sold as a feedstock to petrochemical producers. Because the properties of raw gas are variable, the cost of processing raw gas into market gas varies from one producing area to another.

The end product is market gas of a narrowly defined quality. To accommodate LDCs and large industrial clients, transmission companies in North America have adopted an unofficial standard for market gas. They set the acceptable energy content per thousand cubic feet of gas, and they define the component parts (methane, ethane, etc.) and the moisture and sulfur content of the gas. As a result, natural gas is a commodity; there is no reason to prefer gas from one supplier over another on quality grounds.

History of Natural Gas Developments in Canada

Initially, gas markets were local, serviced by gas from oil production and non-associated gas discovered while exploring for oil. As markets developed for natural gas, producers began to explore specifically for gas, and they developed the infrastructure necessary for gas transmission and distribution. That infrastructure includes pipe that extends from the wellhead to the burner tip plus storage facilities, pumping stations, and metering.

Production of oil and natural gas takes place where the deposits are, and discoveries are often far removed from markets. This is not a major obstacle for oil because the energy content of oil is high per unit volume and it is relatively easy to transport via pipeline, ship, train, or truck. Natural gas, on the other hand, is almost exclusively transported via pipeline, and, relative to oil, the energy content is low per unit volume. Therefore, with the exception of compressed natural gas (CNG) and liquid natural gas (LNG), natural gas doesn't travel well beyond continental boundaries.[3]

Shut-in Markets

Initially, oil-producing areas, particularly those removed from population centres, lacked local customers for gas, just as they lacked gas processing or transmission infrastructure. Gas was viewed as a waste product to be disposed of; flaring was the preferred method. As uses and users began to emerge, the industry faced a shut-in market for gas. That is, because of the absence of pipeline infrastructure, large volumes of gas were shut in, or captive to a small local market, with no access to a larger customer base or large-volume users. Simply put, the arbitrary distribution of the resource meant that supply vastly exceeded demand in certain local markets, while other major markets went unserviced.

Prices naturally reflected these local supply gluts: gas was cheap relative to other fuels, and it replaced close substitutes, such as fuel oil for space heating. The shut-in market led to very low feedstock prices, which attracted petrochemical developments as well as thermal electricity plants and other commercial and industrial users requiring heat generation.

Alberta is an example. In the early days of the petroleum industry, the availability of cheap captive gas led to the development of associated industries, such as petrochemical feedstocks and production of polyethylene and polystyrene. However, cheap shut-in gas was available in Alberta for more than 20 years before that province developed a petrochemical industry.[4] Therefore, favourable prices did not lead quickly to the development of a petrochemical industry; nor did they quickly attract energy-using industries.

Continental/Large Markets

As local transmission and distribution systems were built and interconnected, the local shut-in markets grew into regional markets and finally into a continental market. With continental infrastructure and

[3] Natural gas can be compressed to produce compressed natural gas or compressed and cooled to produce liquefied natural gas, but the cost of CNG and LNG per unit of energy is high relative to oil. Therefore, oil is a better and more economic traveler.

[4] Discussions with officials at Energy Probe and the Alberta Energy and Utilities Board confirm that favourable natural gas prices did not have an immediate impact on attracting new gas-using industries.

a relatively homogeneous product, gas from one production region can enter the system and its energy content can be sold to customers at the other end of the continent. Producers in Alberta or Texas can sell gas to customers in New England or Chicago.

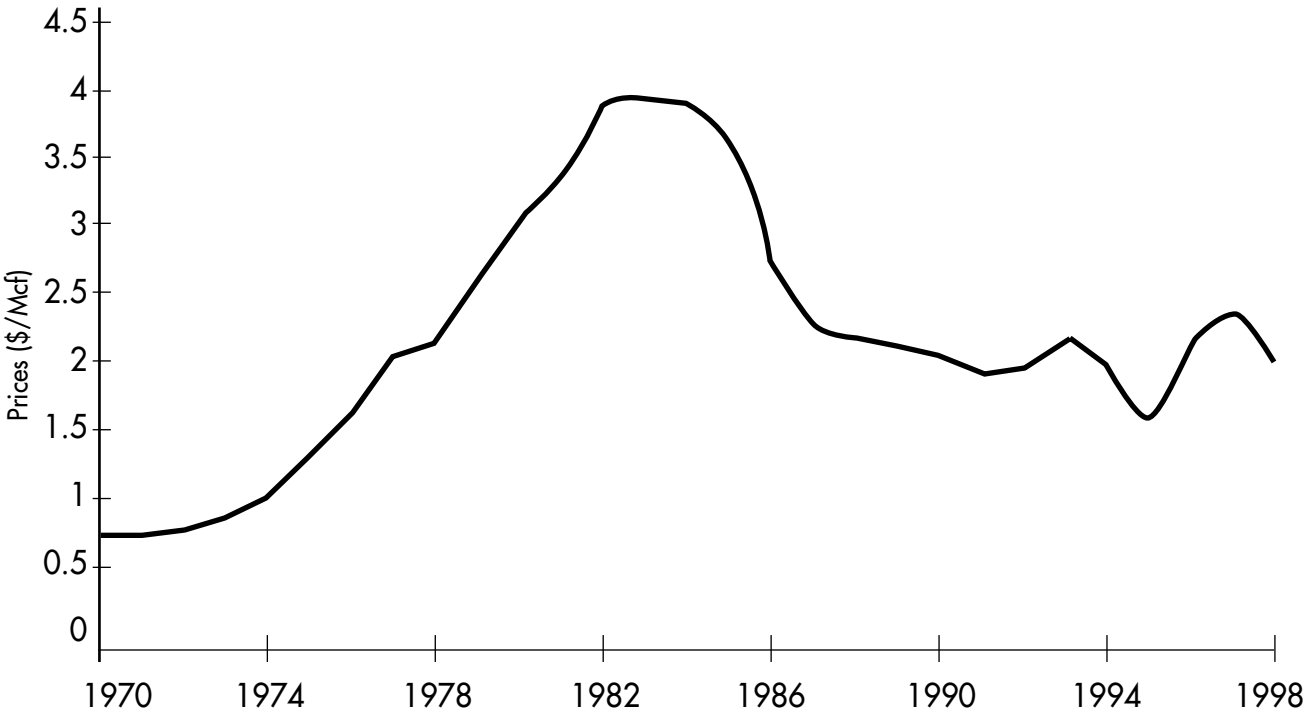
Access to a continental market, therefore, has helped to eliminate the many disadvantages associated with gas production in sparsely (shut-in) populated areas, including pricing, market access, and volume of supply. Access to large markets supported and encouraged the development of small gas deposits far from population centres. While shut-in markets were initially supplied by associated gas (resulting from oil production) and gas from gas fields discovered while exploring for oil, the majority of gas supplying the now geographically expanded system comes from stand-alone gas deposits.

It should be noted, however, that a continental market by itself did not lead to competitively priced natural gas; that required the freeing of market forces from a restrictive and counterproductive regulatory regime. Deregulation of the industry, beginning in the mid-1980s, created a competitive North American market for natural gas, with tremendous benefits for consumers (see Chart 1).[5] Deregulation not only resulted in lower gas prices, but allowed prices to fluctuate with the ebbs and flows of the market. In the winter of 2000/01 the traditional long-running price spread between natural gas and fuel oil on a thermal unit basis disappeared. In North America, increases in gas demand plus supply constraints (including constrained pipeline capacity) led to a rise in price of nearly 70 percent over the 1999/2000 heating season. Higher prices reinvigorated exploration activity, but the normal time lag in areas where the gas transmission infrastructure is already in place is 18 months from the start of a drilling program to its impact on supply. A softening economy and the industry response of using less gas or shutting down marginal facilities, along with some new supplies, have combined recently to bring gas prices back down.[6]

[5] Before deregulation, producers, transportation companies, and distributors protected by regulations and regulators could and did influence or dictate prices and markets. Prices determined by competitive forces were not a reality until the market was deregulated.

[6] The market works. Industry responded to higher gas prices by closing inefficient petrochemical and fertilizer plants as well as by reducing gas consumption. Within a year prices declined significantly.

Chart 1: Wellhead Natural Gas Prices, 1970–1998 (1995 dollars)



Source: adapted from Malloy, 2000.

Not only has a deregulated continental market resulted in competitive prices for natural gas, but a large market is also essential for the viability of high-cost gas deposits such as those found offshore and in the far north. These deposits are costly to develop, and a large market provides a consumer base sufficient to justify the investment in infrastructure to bring the gas to market.

Given the sheer size of the initial infrastructure investment required, the viability of bringing this gas to market depends on two things: a large, secure, and steady market; and sufficient reserves to support that market over the serviceable life of the infrastructure. Both are critical for obtaining financing. In the case of Maritime gas, the necessary market mass can *only* be achieved via access to New England consumers and, ultimately, connection to a large customer base through the continental distribution grid. The continental gas market is serviced by continental supply, of which the Maritimes furnishes a tiny part.

Transmission companies such as Maritimes & Northeast Pipeline must have long-term contracts from shippers (anyone distributing gas) – or the gas would stay in the ground. To ensure that transmission companies have sufficient cash flow to maintain the long-term viability of the main transmission line,

such contracts bind shippers, backstopped by producers, to pay for the transmission charges on the contracted volume of gas (demand charge). Backstopping means that producers will pay the transmission charges on the shortfall if the volume of gas being shipped is less than the contracted volume. A demand charge ensures that the revenue necessary to ensure the viability of the transmission system goes to the owners and operators of the pipeline (Maritimes & Northeast Pipeline in our example). The risk associated with a multi-billion-dollar infrastructure investment is so great that bankers and investors require such contracts and agreements to be in place before pipeline financing is authorized.

The transmission charges (tolling) on Maritimes & Northeast's main transmission line are "postage stamp" charges (i.e., one toll for all customers in a defined area).[7] The National Energy Board sets that toll for all delivery points in Atlantic Canada, and the US regulator sets the rate for New England. Therefore, gas delivered to any point in Atlantic Canada bears the same transmission charge (CDN$0.682 per million Btu (MMBtu)).

Nonetheless, Maritimes & Northeast Pipeline agreed to special short-term discounts on tolls for Nova Scotia and New Brunswick customers. The discount in Nova Scotia is 10 percent for the first eight years and 4 percent for two additional years. New Brunswick customers receive a 4 percent discount for three years. These discounts commenced with gas delivery to NS Power via the Tufts Cove lateral in Nova Scotia and the construction of the lateral to Saint John in New Brunswick. The clock is ticking. While Nova Scotians continue to await the approval of a local distribution company, the discount advantage is eroding away. In New Brunswick, the discount is available to Enbridge Gas New Brunswick's customers (Enbridge is the distributor of gas in New Brunswick), but the market in New Brunswick is building much more slowly than planned. Therefore, this advantage has had a minimal impact.

The Canadian postage stamp toll is added to the US postage stamp toll (US$0.715/MMBtu) for gas crossing the border. US consumers pay the Canadian toll plus the US toll, while all Atlantic Canadian customers pay the Canadian toll alone. Therefore, any diversion of gas from US markets to Canada would reduce the overall revenue received by Maritimes & Northeast Pipeline, assuming that other gas is not substituted for the diverted gas.

For Sable gas, the large market in New England was, and is, foundational (critical) for production. Without it there would be no production.[8] With it, gas can flow and Atlantic Canadians have an opportunity to tap into the line as gas flows through to the United States. In essence we have a "light switch" market. Until the market reached a critical mass to justify the infrastructure, the region had no access

[7]Transmission charges need not be postage stamp. Other common types of tolling are volume-distance, zonal, incentive, and market-based. They can all be designed to generate the same revenues. However, how much individual customers pay would differ. Therefore, each system would have a different impact on attracting customers. Given the small and diverse market in Atlantic Canada, a postage stamp tolling system was deemed the most appropriate to provide equal opportunity for access across the region. Nonetheless, such an approach implies that some consumers are subsidizing the transmission charges of others.

[8] As reported in The Halifax *Daily News*, October 15, 2001, Tom Adams of Energy Probe pointed out that without the US demand we would have no gas development in Nova Scotia.

to gas, no matter how large the resource off its shores (the "off" position). At critical mass, the switch is turned "on." In our case the New England market provided the indispensable critical mass necessary to turn the gas on. This is a simple but critical truth that seems to elude many, and it is at the heart of many of the questions raised earlier about how Atlantic Canadians can maximize the benefits from the availability of natural gas.

In summary, Atlantic Canada does not, and will not, have a pattern of gas development similar to Western Canada. We do not, and will not, have shut-in markets. Our gas largely comes from stand-alone offshore deposits not associated with oil production. Unlike associated gas, our gas bears the full cost of production. Therefore, offshore gas requires a large market to justify the needed production and transmission infrastructure.

So how do we maximize the benefits from the availability of natural gas?

Gleaning the Benefits

Why is the United States the first consumer of our gas?

Underlying this question and the others posed in the introduction to this paper is the quite reasonable belief that Atlantic Canadians should be the primary beneficiaries of their own natural resources. But there are many ways to benefit from natural gas, and having first claim on the resource, or enjoying a below-market price are not the only, or even the best, strategies to pursue.

The question of why we are selling our gas to Americans has already been answered in general terms, but it might be helpful to delve into it in more detail. Stand-alone gas bears the full cost of production plus the infrastructure costs to get it to market. In the case of the Sable Offshore Energy Project and the Maritimes & Northeast Pipeline, the minimum economically viable production plateau is 560,000 gigajoules (GJ) of gas per day.[9] By comparison, SOEP was asked to reserve, for the first three years of the project, 10,550 GJ/d for the Nova Scotia market. Therefore, only a large market such as New England can generate the critical mass necessary to justify the investment in infrastructure. In our case the New England market is literally paying the freight. The volume of gas necessary for the viability of the line is guaranteed by shippers in New England, who contract for capacity. Producers have undertaken to backstop any shortfall.

Diverting large volumes of gas to the local market and paying only the Canadian transportation toll would mean a decline in transmission revenues (the US toll is lost) and the viability of the transmission facilities would be weakened, unless the diverted gas were replaced. The economics of the pipeline

[9] A gigajoule is a measure of thermal energy, the metric equivalent of 0.948 MMBtu.

depend on selling the near capacity of the line in New England. Therefore, without the New England market our gas would stay in the ground, generating benefits for no one.

The second frequently asked question is, Why don't we sell it really cheaply to ourselves and only charge US consumers the full price? The answer is that the gas we consume at below-market prices could have been sold at market prices and these funds used to our benefit. Let's say we sell natural gas to ourselves at half the market value – we, as owners of the resource, are forgoing half its market value. Such artificially low prices encourage over-consumption and reduce the revenues we would have received had we sold the same gas at market price. And by reducing the price we artificially increase the demand for the gas of whose value we are now giving up a major share – again increasing the wealth that we are forgoing.

The market value is simply the opportunity cost of the natural gas; that is, the opportunity forgone or given up by not selling it. We are always better off receiving the market value for our resources because by doing so we are choosing the greatest return for the resource that we own.

Let's consider who the "we" is. Is it the producer? Should SOEP produce gas and sell it to Atlantic Canadians for less than market value or at a loss? Is it the transmission company? Should Maritimes & Northeast Pipeline transport the gas at a loss? What about local distribution companies (LDCs); should they lose money on distributing gas, or should their shareholders be expected to accept low returns? None of these private sector firms will produce, transport, or deliver gas at a loss or at a return below market rates. Who would invest in a project for which the returns are low by decree of the government or through regulation?

The "we" can only be the citizens of Atlantic Canada. As taxpayers, we would have to subsidize producers, the transmission company, and LDCs or, alternatively, subsidize directly the consumers of gas. We would be required in perpetuity to underwrite a portion of the cost of delivered gas. Among the "we" are owners of electricity- and oil-heated houses who would be subsidizing their neighbours who use gas – hardly a reasonable or equitable mechanism for the redistribution of income.

Artificially low prices not only encourage increased consumption and waste but also cause a misallocation of resources. Either we would be telling companies and their shareholders to give up revenues they could have received if the gas were sold at market prices or, more likely, our taxes would rise in order to subsidize our neighbours so they could switch from oil or electricity to gas. Reducing everyone's disposable income to subsidize gas usage means we have less to spend elsewhere in the economy. Therefore, the jobs and benefits gained in the gas sector are lost in areas where the funds would otherwise have been spent.

A third frequently heard question asks why we don't charge premium prices to US consumers, since they are gas hungry. But natural gas is sold in a continental market, and no single producer or distributor can control price. As well, gas faces price competition from close substitutes. There is no branding or mar-

ket differentiation and customers will, over time, move to the lowest-cost fuel. The strategy of price gouging works only in the short term when energy in general is in short supply and switching cannot be done quickly or cheaply. However, fuels that are differentially more expensive will lose market share over time. A strategy of charging premium prices is a shortsighted business model with long-term negative consequences, leading eventually to a smaller market share. Therefore, it is not ultimately in our best interest to have a made-in-Atlantic Canada preferential price for natural gas or to charge American customers a premium.

The fourth question is, Why not force LDCs to provide the majority of Atlantic Canadians access to the gas distribution network, regardless of the economics, as the quid pro quo for having a franchise? The delivery of gas to customers where the cost of gas distribution exceeds its revenue will force subsidization of non-economic users, thereby raising average delivery costs and prices. One might ask what is wrong with this – we subsidize individuals and groups all the time. Why shouldn't we subsidize uneconomic users to create jobs by giving them cheap gas?

Subsidies do indeed benefit those being subsidized, *but at the expense of everyone else.* Say it costs me $1,000 per year to heat my house with gas at market price. Now suppose the utility charges me $1,100 for the same gas and uses the $100 to cover the costs of providing subsidized service to non-economic users. Wouldn't this create some extra jobs?

It sounds good until the frame of reference is broadened. Without artificial cross-subsidization, I have gas to heat my house and $100 to spend on other goods and services. With cross-subsidization, I just have the gas. Therefore, the jobs and income I would have created by spending the $100 are lost. Yes, jobs have been created in the gas industry by artificially subsidizing some users. But experience shows that such misallocation of resources and economic inefficiencies – taking into account their combined effects across the economy, not just within the subsidized industry – almost always destroy more economic value than they create.

Even within the industry, the effects are perverse. By definition, not all users can be subsidized. At $1,100 per year for unsubsidized users, there will be fewer people willing to switch to gas. People also respond to higher prices – they buy less. Subsidies affect more than value and prices. They can jeopardize the viability of the distribution system.[10]

[10.] The two-priced system for crude oil adopted in Canada in the 1970s and '80s is an example. So too is the subsidizing of grain transportation under the now-defunct Crowsnest Freight Rate and Feed Freight Rate Assistance programs. Such programs are not sustainable over time.

In summary, the gas industry both gains and loses. In addition, jobs outside the gas industry are lost because higher gas prices siphon income away from spending elsewhere in the economy. The net results are, on balance, negative. Therefore, mandated targets for gas delivery or artificially low prices, while politically popular, are counterproductive and damage the larger public interest.

If policies and regulatory frameworks that allow us to keep the gas for our own use or have artificially low prices or subsidize gas distribution are not wise choices, what should we be doing? How do we best generate benefits from the availability of gas in the region?

The question now becomes how much government oversight of the gas industry is needed or appropriate to protect the public interest while ensuring economic efficiency and the viability of the system.

WHY REGULATE?

Market forces and regulations, by design or function, are both intended to influence behavior; that is, they determine the allocation of goods and services as well as resources. Transactions in the market are voluntary, and they are efficient in the sense that they result in optimum quantities produced and sold at the lowest price. Under regulation, transactions are controlled or mandated (i.e., involuntary).

If the market is working, regulations are not required – they add no value to society and they are counterproductive. Therefore, when we are dealing with private goods like natural gas, we should regulate only when the market fails to work.[11] Regulations are at best a proxy for the discipline of the market. Where applicable, the efficiency of the market is always preferable.[12] That is to say we should only regulate where we have real or expected distortions or failures in the market as well as unaccounted externalities. How well does the market work for the natural gas industry?

The natural gas industry is characterized by three distinct elements: the commodity, the main transmission system, and the distribution (LDC) system. Generally, only the latter deals with the ultimate consumer.[13] The producers provide gas to transmission companies, which in turn transport it to LDCs for distribution to final users. One of the main rationales for regulating an industry is protection of the public from the potential of predatory pricing inherent with monopoly power. Other reasons for regulation include the impact of externalities such as health, safety, and the environment.[14] The degree to which monopoly power exists, or could exist, in these various components of the natural gas industry is a relevant question to think about before we consider an appropriate regulatory framework.

Natural Gas as a Commodity

Natural gas competes with other fuels and other sources of energy throughout North America, and now it will increasingly do so in Atlantic Canada. Natural gas often competes on a thermal unit basis, and it competes increasingly on its environmental qualities, especially for large-volume users and where

[11] Private goods are goods sold in the marketplace. They can be produced by either the private sector or the public sector. Natural gas is a private good despite its ownership by the Crown because it is sold in the marketplace.

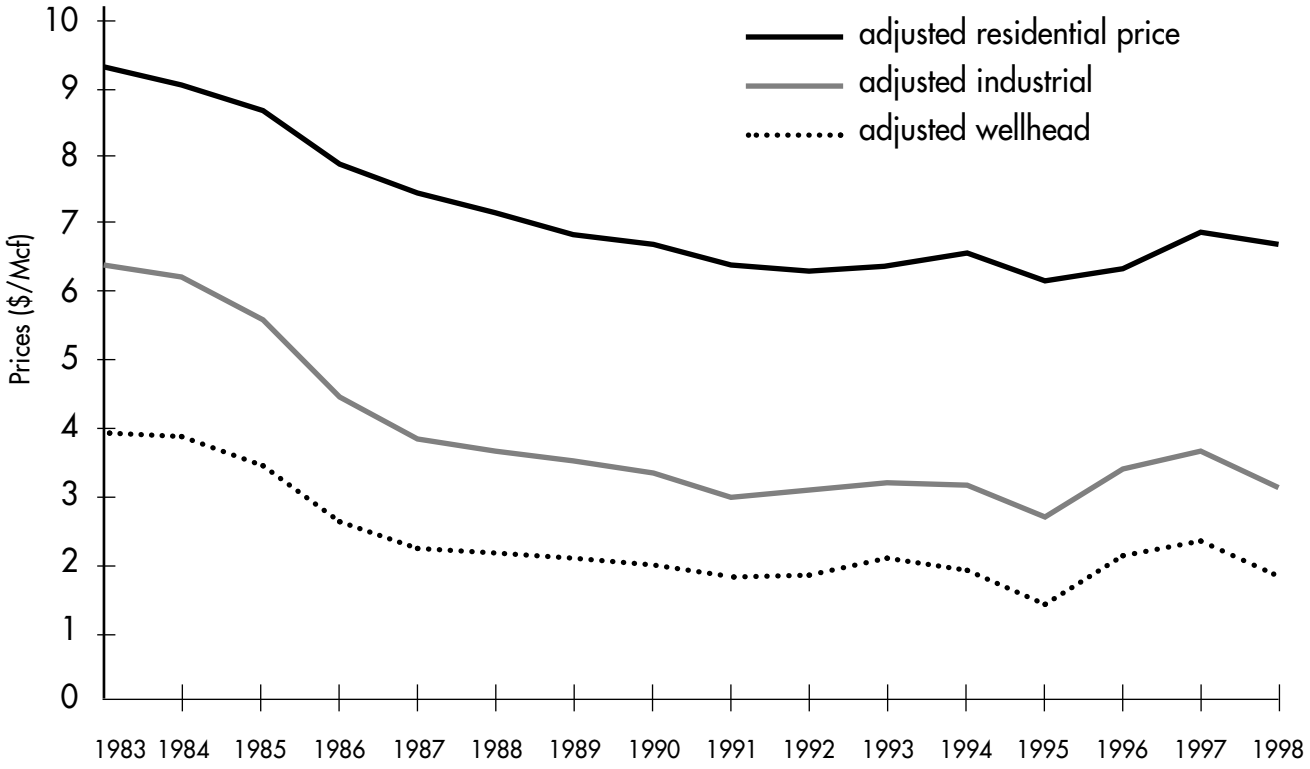
[12] The case in favour of free markets and minimal government as a means of achieving maximum economic efficiency and, therefore, return to society is pervasive throughout economic literature. One particularly entertaining account of it is to be found in Frédéric Bastiat's nineteenth century classic, *The Law* (Bastiat, 1998).

[13] Large-volume users can connect directly to the main transmission line. The implications of industrial bypass policies will be dealt with later in this paper.

[14] Workplace and consumer health and safety standards, as well as air and water quality concerns, are not unique to the gas industry, and regulations regarding them are not industry specific. The focus in this study is on the rationale for regulations unique to the natural gas industry.

there are strict emission limits. Apart from its clean burning properties, it is a commodity (unit of energy) facing competition from close substitutes. In a continental or large market where consumers may choose from a mix of energy alternatives, the price of natural gas as a commodity is fully exposed to competitive forces. Therefore, natural gas producers do not have the potential to extract monopoly profits on market gas. At Plugging in Atlantic Canada, an AIMS conference in Halifax on October 27, 2000, Ken Malloy clearly demonstrated how competition in the natural gas market has resulted in residential, industrial, and wellhead price reductions of 35 percent, 58 percent, and 61 percent, respectively, since 1985, when deregulation commenced in both the US and Canadian markets.[15] Competition does indeed impact the commodity price of natural gas (see Chart 2).

Chart 2: Wellhead, Industrial, and Residential Natural Gas Prices, 1983–98 (1995 dollars)



Source: adapted from Malloy, 2000.

[15] Ken Malloy is president of the Center for the Advancement of Energy Markets (CAEM). Ken and CAEM were named by *Public Utilities Fortnightly* as one of five "Energy Innovators: Ringing in an Age of Enlightenment." CAEM is an independent, non-profit think tank committed to an objective analysis of how technology and restructuring will transform energy markets.

Transmission

Transportation involves the construction, commissioning, operation, maintenance, and decommissioning of a high-capacity pipeline transmission system – usually interprovincial and/or international. Interprovincial transmission companies normally deliver high volumes of gas to a small number of delivery points, which results in a low per unit transportation charge. In 1999 these costs represented about 19 percent of the residential delivery cost in the United States.[16] Because of the high infrastructure costs involved, a large volume of gas is required to justify the initial investment in a transmission line. Financing a system usually requires that the volume of gas needed to make the system viable be contracted for in advance of building it. Therefore, a critical mass of customers must be signed up in advance of the system being built. Markets must be large enough to justify the infrastructure.

Several large transmission lines can serve a large and concentrated market such as New York, Boston, Chicago, or Toronto. However, a remote or greenfield site such as Atlantic Canada can only with difficulty justify more than one outbound pipeline, and transmission to smaller centres often depends on their being on or near routes to major markets. Multiple transmission systems to the same market from a remote site are normally uneconomic. Therefore, an interprovincial transmission system, particularly from a greenfield site, does initially have the characteristics of a natural monopoly, and the National Energy Board regulates such systems.[17] Over time, however, as gas demand builds beyond the capacity of the initial transmission system, a competing pipeline could be justified. In fact a second pipeline connecting Scotian Shelf gas to the New England market is now under consideration.

Distribution and Delivery

Gas transmission companies move high volumes of gas from the wellhead to local distribution companies (LDCs), which in turn deliver it to local customers (industrial, commercial, institutional, and household users). LDCs own and operate local delivery systems composed of a massive network of small-diameter pipe, which moves low volumes of gas to numerous delivery points. Because local delivery systems have high fixed costs and low variable costs, the delivery charges are much higher per unit of gas than are main transmission charges. In 1999, distribution costs were roughly 47 percent of the residential delivery price.[18] The capital cost of distribution infrastructure prohibits multiple LDCs in a local market, and the distribution of natural gas can therefore have the attributes of a natural monopoly. However, this is not the case for a greenfield (previously unserviced) market such as Atlantic Canada.

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[16] The Energy Information Administration of the US Department of Energy estimates that on average (national US average) 34% of the residential natural gas price is for the gas itself (commodity), 19% for transmission to the LDC plus storage, and 47% for distribution to customers.

[17] Transmission systems are regulated federally and are therefore outside the purview of provincial regulators.

[18] See note 16.

Here, natural gas has nearly a zero percent market share and, relative to electrical utilities and the home heating oil industry, has little or no market clout. Atlantic Canada has a mature energy market, dominated by electricity (generated by several fuels, including coal and nuclear power), fuel oil, and wood, with propane playing a less prominent role.

In a broad context within the region, therefore, gas distributors currently have no monopoly power and are at the mercy of the other dominant players in the industry. Except for propane, there is a significant cost to switch to and from the use of gas. From the perspective of individual customers, once they decide to convert to natural gas they are in a sense captive. Nonetheless, LDCs that attempted to raise prices for these captive consumers would forgo potential customers by discouraging switching. Therefore, natural gas LDCs initially do not have market or monopoly power; this is the current circumstance in both New Brunswick and Nova Scotia. Regulations to protect customers from the nonexistent market or monopoly power of gas distributors are therefore unnecessary in Atlantic Canada. Initially, there is no rationale for regulating the distribution system. However, as LDCs build market share, regulations may have a role to play in protecting customers and ensuring the integrity of the system. The rationale for regulation builds only as the market share of gas builds.

Nonetheless, because of the natural monopoly inherent in gas transmission (at least for the inaugural system) and the perceived monopoly for gas distribution, regulators and investors tend to prefer exclusive franchises for geographic areas. Interprovincial and international transmission pipelines are regulated federally by the National Energy Board (NEB). The responsibility to approve and regulate distribution and delivery of gas rests with provincial authorities. The regulatory responsibility for lateral pipelines depends on whether they form part of the interprovincial transmission system or the local distribution system. In the former case, they are regulated by the NEB, in the latter case by the province. To date, the NEB regulates the laterals built in Nova Scotia and New Brunswick.

Even if governments as regulators do things correctly, the gas distribution system in both New Brunswick and Nova Scotia will take at least 20 years to develop. Therefore, natural gas could likely go from being an insignificant player in the energy market to holding a significant market share. The need for, and usefulness of, regulations will change as the market evolves. To gain a better appreciation for how this evolution will impact the industry, we need to understand the basic economics of the industry, particularly with respect to building the system and building a market from scratch.

Economics of Gas Transmission and Distribution

The natural gas industry is characterized by massive up-front capital costs, which translate into very high fixed costs and very low variable costs. Such characteristics have two glaring implications: (a) capital costs, and thereby fixed costs, are absolutely critical to the economic viability of the industry; and (b) the strict adherence to marginal costs or marginal cost pricing just doesn't work all that well with this industry. (The marginal cost of delivering an additional unit of gas to consumers already connected is insignificant and effectively approaches zero.) Therefore, capital costs dominate the industry, and how capital costs are recovered in gas pricing is critical.

Normally, in a capital budgeting decision a proponent of a gas distribution system will compare – on a present value basis – potential profits (returns) with the capital costs; that is, the proponent will discount all costs and returns to the present and compare them on either a net-present-worth or rate-of-return-on-investment basis. If the capital costs are too high, the return will not justify the risks and the investment will not be made.

Regulators normally use one of two general approaches to handling capital costs when determining the price of transporting and distributing natural gas: the cost of service (CoS) model; or a performance-based (PB) or market-based model, which has numerous variants. At its core, the CoS model has a guaranteed or regulated rate of return on invested capital. The PB model does not provide a guaranteed rate of return, but potentially allows the LDC to capture high returns in later years as the market develops. The PB system trades off losses over the initial years with high returns over the later years. The CoS model is used almost exclusively for main transmission lines, while regulators have used both approaches with LDCs. Which system is the most appropriate for an area such as Atlantic Canada, where gas is a new source of energy?

Cost of Service Approach

With main transmission pipelines, the NEB authorizes a rate or price schedule based on approved costs with a built-in profit margin. This is known as a regulated rate of return or a regulated return on equity. Normally the NEB allows one return for equity and one for debt, resulting in a blended return. Under this approach a company is allowed to calculate its cost of service, which includes the following elements:

- cost of capital, including
  - interest on debt for assets in rate base
  - depreciation
  - regulated return on equity
- operating and maintenance costs
- taxes, including
  - municipal
  - capital
  - corporate income tax

The total cost of service is calculated annually and is seen as the revenue requirement of the company. This is the revenue required to cover costs and give an adequate return to investors. The company estimates the volume of gas to be transported annually (throughput) and divides that volume into the revenue requirement to determine the average cost per unit of gas delivered. For the main transmission line the contracted volume must provide sufficient revenue to justify the initial investment.

For LDCs moving into a new market area, however, the volume of gas required to serve the initial customers seldom, if ever, guarantees sufficient revenues to justify the infrastructure. If an attempt were made to recoup the cost of service in the initial years before adequate market share is acquired, natural gas would be uncompetitive. To help build the local market, the price of gas is typically discounted below that of home heating oil (often a fixed percentage of the home heating oil price). The losses experienced by the LDC in the earlier years are tabulated and accumulated in a deferral account. In later years, as the volume of gas consumption increases and the cost of service per unit of gas drops below the discounted price, the LDC maintains the price at the set discount level. That discount level is maintained until the deferral account reaches zero. Then the distribution toll for gas drops to the calculated cost of service.

The CoS model is a trade-off that helps mitigate early losses but controls the level of profit in later years as the cost of service plummets and the infrastructure is paid off. This approach was adopted in New Brunswick. The delivered price of natural gas is discounted below the price of home heating oil in order to build market share. Once the cost of service plus the commodity price goes below the discounted price, the franchisee will be allowed to maintain the distribution charge at that level (i.e., higher than the cost of service) until the deferral account is exhausted. Thereafter the regulator ensures that the distribution charge reflects the annually calculated cost of service. In the long term this effectively puts a cap on the rate of return – to the blended return on equity and debt specified in the cost-of-service formula.

Impact of the Regulated Rate of Return

The regulated rate of return element of the CoS model not only serves to guarantee investors a return on their equity – it also makes the franchisee less sensitive to capital costs. Because the franchisee receives a guaranteed return on capital invested, the greater the amount of capital invested the greater the return, in absolute terms. Therefore, the CoS model can accommodate some "gold plating" of capital costs. In practice the franchisee submits a development plan to the regulator for approval. As long as the regulator deems the plan reasonable, the regulator approves it. To a point, therefore, the higher the capital costs the more return the franchisee will make and the better off it is. That "point" is reached when gas becomes uneconomic relative to substitutes. Therefore, under a regulated and guaranteed rate of return on equity, the incentive to minimize capital costs can be blunted. This distortion may be an acceptable trade-off to ensure the viability of the system, particularly as it goes through startup difficulties.

Performance-based or Market-based Approach

The second approach used by regulators for handling capital costs is the performance-based model. It includes market-based pricing or franchise bidding and has numerous variants. It does not provide a regulated (guaranteed) rate of return, but allows the franchisee to accept a larger risk (experience greater losses) in the earlier years as it builds markets. The quid pro quo for accepting this risk is that the franchisee is allowed to receive much greater profits in the later years. This approach was originally proposed by Sempra Gas in Nova Scotia and accepted by the Nova Scotia Utilities and Review Board.

One form of the market-based approach, known as the Retail Price Index plus or minus an efficiency factor (RPI ± *X*), has been adopted in the United Kingdom for the regulation of its electric utilities. It has been used with mature industries to provide the LDC with an incentive to make the system more efficient and to ensure that customers are protected by keeping profits at the minimum necessary to maintain the integrity of the system. In a Canadian context it would be called the Consumer Price Index plus or minus an efficiency factor (CPI ± *X*). The regulators assess and approve the transmission, distribution, and operating and maintenance costs (which have profits built in) and determine the base price, excluding the commodity, necessary to ensure the viability of the system. The delivered price is the base price plus the commodity price. The base price is adjusted yearly by the Consumer Price Index. As well, an efficiency factor *X* is periodically either subtracted to squeeze out excess profits or added to ensure adequate revenues to maintain the integrity of the system.

By way of illustration, in the United States in 1999, combined transportation and distribution charges made up approximately two-thirds of the delivered price of natural gas. The remaining one-third of the price was the commodity. Because the commodity price is beyond the control of an LDC, it is not factored into the formula, but is added on after the formula is applied. Therefore, in 1999 the CPI ± *X* would apply to only about two-thirds of the total cost of delivered gas. The efficiency factor *X* (added

or subtracted to ensure that profits are just sufficient to maintain the integrity and viability of the system) remains in effect for a set period of time (three to five years), before it is recalculated. The LDC is allowed to increase the base price annually (excluding the commodity portion) by the CPI. If it incorporates efficiencies, it is allowed to keep the extra profits for a period – until *X* is recalculated at the end of the period to squeeze out excessive profits. Nonetheless, profits are maintained at reasonable levels – only extra or excess profits are squeezed out of the system. This approach gives an incentive for LDCs to become more efficient, because they get to keep any extra profits they generate until the regulator next recalculates the efficiency factor. Thereafter, the price is readjusted to the minimum deemed necessary to keep the system operating on a sustainable basis, which benefits consumers. In the short term, therefore, LDCs reap the benefits of system efficiencies, while in the long term the benefits of such efficiencies are transferred to consumers.

Under the CoS model the cost of service is calculated annually and LDCs do not reap the benefits of efficiencies; they have no pressing incentive, particularly in a market dominated by gas, to seek efficiencies, and can become bloated and complacent. The CPI ± *X* model works well for a mature industry, for which the system is in place and new capital requirements are minor in comparison to the value of existing infrastructure. However, its applicability to a new greenfield natural gas distribution system is not proven or demonstrated.

Summary – Economics of Transmission and Distribution

In summary, we have learned a number of things:

- Maritime gas is non-associated gas, and therefore must bear the full costs of production as well as transmission and distribution.
- The infrastructure costs of getting offshore gas to market are extremely high.
- Capital costs are the critical factor in determining the economics of pipelines and distribution systems.
- Because of dispersed populations, even if every home and business were using gas, the Atlantic Canadian market could not justify that investment in infrastructure.
- Therefore, a large market is required to justify the investment in production and transmission facilities.
- We need the New England market to have access to our gas. Without it our gas would stay in the ground.
- Demand charge and a postage stamp price are integral parts to financing and ensuring the viability of transmission systems.
- Regulations specific to the natural gas industry are required only when markets fail to work.
- There is no compelling argument that market distortions or failures are inherent in a greenfield gas market like Atlantic Canada.
- As gas increases its market share and as the market matures, LDCs gain market power and can exhort control over prices (monopoly power).

- Regulators usually use one of two systems in handling capital costs: the cost of service model, and the performance-based model. The former can result in higher capital costs and does not provide an incentive for LDCs to become more efficient over time. However, that may be the trade-off necessary to lower risks and ensure investment as the system is inaugurated.
- As the gas system matures, a performance-based model will encourage efficiencies and provide greater benefits to consumers.
- Therefore, the need for regulation and the types of regulations required will evolve over time as the system develops.

We now need to look at one final piece before we can make an informed recommendation for the best regulatory and policy framework to support natural gas distribution in Atlantic Canada. Given the foregoing, what would persuade you or me to switch to gas if it passed by our front doors?

Market Economics

Why Switch to Natural Gas?

For a region where many people feel that the chief benefits of natural gas arise when the gas is consumed within the region and not exported, we seem to face a paradox: hardly anyone is signing up to buy natural gas. This absence of demand for a major energy source within the region might suggest that the public policy framework for natural gas has made switching from alternative fuels unattractive or that the market is not all that inviting.[19] After all, no one would switch to natural gas without seeing an advantage in doing so, likely in the form of cost savings. And those savings would have to be sufficient to justify using gas as opposed to some other fuel. What is the economic imperative for Atlantic Canadians to switch to gas?

The decision to use gas is based on several factors:

- the spread in price between natural gas and the current fuel being used[20]
- the expectations for that spread to persist over time
- the cost of converting to gas-fired equipment
- the expected interest rate

From the perspective of the customer, the first two factors relate to operating costs: Is natural gas cheaper at the burner tip, on an energy unit basis (per gigajoule), than substitute fuel, and by how much and for how long? The last two factors involve a capital budgeting question: Is the investment in gas-fired equipment worth it? The final decision is based on a combination of both the operating cost savings and the capital cost.

Price Discounting to Build a Market

Would I switch to gas because it is cheaper per thermal unit than, say, home heating oil? I would if my existing oil furnace needed replacement and the costs of a new high-efficiency gas-fired furnace and a new high-efficiency oil-fired furnace were comparable (i.e., if the capital cost of the comparable equipment has no bearing on the decision). However, the answer is not so simple if these costs are not comparable, or if my current equipment is not worn out. In the former case I need to account for the dif-

[19] Alberta gas has been delivered to Quebec City and New England for decades. Trans Canada Pipeline Limited had the option of extending its system into Atlantic Canada, but chose not to for economic reasons. TCPL judged the economic prospects of the Maritimes as marginal.

[20] The price of natural gas seen by the customer includes the commodity price and the transmission charge plus the distribution charge.

ference in cost between the two appliances (differences in capital costs). In the latter case I am disposing of serviceable equipment in favour of gas-fired appliances. Then the capital cost of the gas furnace or gas insert is very much of relevance to my decision. Now the question becomes, Can I save enough on natural gas to justify the investment in new or retrofitted equipment? Put another way, What is the payback or rate of return on investment from switching to gas fired equipment?

Influence of Equipment Costs

If the rate of gas penetration into the market depends solely upon the new or the replacement market, LDCs would not build volume fast enough to justify the up-front capital costs of the distribution infrastructure. The new-construction market can be erratic, and, assuming that the expected life of heating equipment is 25 years, on average only 4 percent of existing heating equipment would be replaced annually. Therefore, to build a customer base, LDCs must also encourage a portion of the existing market to switch from its current fuels to natural gas before existing equipment is fully depreciated. This could be accomplished either by prematurely replacing equipment or by retrofitting existing equipment with gas burners. The cost of retrofitting propane and fuel oil systems to burn gas is significantly less than the cost of replacing existing systems with new gas-fired appliances. Various types of inserts or retrofitted gas equipment for propane and oil-fired systems are CSA approved and accepted in other provinces and, barring unforeseen safety concerns, should be accepted by regulators in Atlantic Canada. However, gas is so new that some provinces such as Nova Scotia have not yet written regulations or set standards in this regard.

This switching scenario does not fully apply in the case of electrically heated homes, which generally speaking are the least likely to switch to natural gas. Replacing electric baseboard heating with a forced air or hot water heating system fueled by gas entails a major expense, including not only the costs of the equipment but renovations to the structure to accommodate heating ducts or pipes. Such capital costs are normally too high to justify total conversion under normal circumstances. However, partial conversion, or the use of gas for supplemental heating, is a large potential market for homes whose primary source of heat is electricity. Converting to gas-fired hot water tanks, gas fireplace inserts, gas cooking stoves, and gas heating on the lower level of the home while maintaining electrical baseboard heating on upper levels are common types of partial conversion of electrically heated homes. A compensating factor for higher conversion costs is the high price per thermal unit of electricity relative to gas.

During the 1980s the federal government had an “off-oil” program, which provided homeowners with grants of up to $1,000 to convert from oil to an alternative fuel. In Atlantic Canada conversion to electrical or wood heat were the only practical alternatives. At that time, NB Power commissioned the Point Lepreau nuclear power plant, and the utility used the federal program as an opportunity to build load for its new generating station. Currently, 60 percent of homes in New Brunswick use electricity as their primary source of heat. Such a high percentage will reduce the potential market (volume) for natural

gas. Such a high percentage of electrically heated homes, particularly in New Brunswick, is not the best news for LDCs seeking market share for gas.

Environmental Benefits

For commercial, industrial, and institutional users of gas, pollution abatement costs may also become a consideration. For many such users, pollution abatement costs can be a real influence on profitability. If natural gas is a cleaner fuel than the fuel currently being used and if burning gas lowers the environmental abatement and mitigation costs paid by the industrial user, or helps the user meet mandated standards, then these real savings become a positive element in the capital budgeting calculation – by lowering their operating costs. This benefit only applies to the environmental costs and benefits internal to the firm using natural gas. The replacement of coal with natural gas may well have a positive environmental benefit to society, but if a firm cannot capture those benefits on its bottom line, they become irrelevant to the capital budgeting decisions of the private sector; that is, they are externalities.

Summary – Market Economics

In summary, the decision to use gas is not solely based upon lower gas prices (operating cost), but is rather an investment decision on the part of the customer. Therefore, to encourage switching to natural gas, the spread or margin between the cost of delivered gas and alternative fuels must be sufficient to justify the investment in the new equipment. If an average home spends $1,200 per year on heating oil, a 5 percent discount, for example, would mean saving $60 per year, which would have to be compared with the capital cost of switching fuels. A $60 saving over 10 years discounted to the present at 5 percent would have a present value of only $460. At a higher interest rate the present value would be even lower, hardly sufficient to encourage switching. Therefore, the larger the margin the greater the return or the shorter the payback period. The narrower the margin the lower the return and the longer the payback period.

We now have enough information and background to judge how well governments in Atlantic Canada are doing with respect to fostering natural gas distribution, and we can begin to examine which regulatory model would likely work best in launching the gas industry in a greenfield market such as Atlantic Canada.

What's Happening in Atlantic Canada?

The take-up of natural gas in New Brunswick and Nova Scotia has been disappointingly slow.[21] Other than large industrial users such as the Irving refinery in Saint John or the Tufts Cove power plant in Dartmouth, the only take-up of natural gas has been by users of propane in New Brunswick (e.g., restaurants in Moncton and Fredericton). Because the spread between propane and natural gas prices is high and the cost of conversion is minimal, propane consumers are choosing to switch. However, other potential customers using other competing fuels are not choosing to switch in large numbers. Why not?

People will switch only if they see consumption of gas as beneficial. In Atlantic Canada the abundance of gas, by itself, will not necessarily provide Atlantic Canadians with a favourable price advantage over other fuels; nor will it give them an advantage over gas users elsewhere in North America:

- Offshore natural gas only became available in Nova Scotia and New Brunswick because a market in New England was developed. Therefore, the New England/North American market determines the price of gas that Atlantic Canadians consume.

- Unlike the early development of Western Canada's gas market, Atlantic Canada inaugurated gas production by being connected to the North American continental market via New England. Shut-in markets have low prices based on lots of captive gas and a small customer base. A continental market has a large number of producers and distributors competing with each other for customers. No buyer or seller can influence the price. Such a market produces an undistorted competitive price.[22]

- Demand charges guarantee that the revenue necessary for the viability of the pipeline is available to the transmission companies. Such contracts lower the risk and are instrumental in procuring financing. The economics of pipelines, particularly for inaugural infrastructure, benefit from such contracts. This means that the transportation plus commodity charges for all customers in Atlantic Canada are the same, regardless of their location.

[21] Currently, natural gas is available only in New Brunswick and Nova Scotia. Hence, the analysis will concentrate on these two provinces. However, as gas from offshore Newfoundland and Labrador, and possibly PEI, becomes available, these provinces will be faced with the question of developing their own distribution and regulatory process. Therefore, the analysis in this section of the paper applies equally across Atlantic Canada.

[22] Gas prices are often quoted in terms of the Henry Hub price. Henry Hub is a junction or node in Louisiana where numerous independently owned transmission lines intersect. At Henry Hub, no buyer or seller of gas is large enough to influence the price. It is considered one of the most liquid points in the North American system, where gas prices are pure (least distorted). Although there are a number of such points in North America, the NYNEX futures market has adopted the Henry Hub price.

For these reasons the price of our gas in Atlantic Canada is derived from competitive forces in effect across North America. Given competitive pricing, lets look at how the market is developing in New Brunswick and Nova Scotia and how regulations are affecting the evolution of that market.

New Brunswick

New Brunswick has opted for a cost of service (CoS) model for gas distribution. The province has also chosen to unbundle services. *Unbundling* means that the sellers or marketers of natural gas and the local distribution company (LDC) of natural gas are separated. Enbridge Gas New Brunswick (EGNB) is the LDC, but it is not allowed to market natural gas directly to customers. Customers must buy gas from one of the provincially approved marketers of gas. This means that EGNB has no control over, or direct involvement in, signing up new gas customers. EGNB must rely on independent marketers to sell gas to customers before it can connect them to its distribution system.

To attract customers EGNB has set an average discount rate for gas relative to heating oil of 30 percent for homes, 15 percent for commercial users, and 5 percent for large industrial users. Given the unbundling of services, EGNB controls only distribution and delivery costs. In order to realize these discount rates the company has to work with the gas marketers; that is, to reach the desired level of discount, the marketers must agree to reduce their profit margin (marketers' margin) and EGNB must lower its distribution charge.[23]

Aside from very large users such as the Irving refinery in Saint John, the results have been minimal penetration into the home heating oil market and only limited penetration into the commercial and institutional market, largely replacing propane use. EGNB estimates that it will connect 70,000 customers over the next 20 years. The company estimated connecting 3,700 customers in its first year, but managed to sign up less than 15 percent of this target. The setting up of a separate gas marketers' network plus the time involved in negotiations between EGNB and the various marketers are significant factors in the slow uptake of customers. It is not clear how consumers benefit (or what the economic rationale in a greenfield market is) from separating marketing and distribution of gas and excluding the distributor from marketing gas. Allowing the LDC to market gas as a means of building the market and having a better control over discounting seems both reasonable and prudent.

Another policy adopted in both New Brunswick and in Nova Scotia provides for an "industrial bypass," whereby large industrial users (anchor-load customers – the Irving refinery, for example) can enter into

[23] The delivered cost of gas includes the commodity portion that goes to producers and the transmission charge that goes to Maritimes and Northeast Pipeline. Neither of these portions is discounted. Therefore, any discounting must come from the marketers' margin and distribution charges.

an agreement directly with the transmission company to serve their requirements.[24] Industrial bypass agreements can create cash flow problems for LDCs, but they can also bring gas to large clients and markets that otherwise might not be served. On balance, such agreements should be used only when the benefits to customers outweigh the negative impact on LDCs.[25]

Nova Scotia

Nova Scotia is about to conduct hearings for the second time to award a franchise. Sempra Gas, winner of the first franchise award, pulled out after requesting significant amendments to its original agreement. Unlike New Brunswick, Nova Scotia, at the request of Sempra, had opted for a performance-based (PB) or market-based regulatory model. In addition, the province required that a specified number of households and counties have access to gas irrespective of the economics. Another significant difference was the discount rate (5 percent) set by Sempra to build market share.

The provincially mandated delivery of gas to customers where the cost of gas exceeds its revenue would force subsidization of non-economic users. But, as discussed earlier in this paper the argument in favor of creating jobs through subsidizing non-economic users by giving them cheap gas is ultimately self-defeating. In the short term, new jobs would be created in the gas industry, but experience time and time again has shown that the jobs created are always fewer than would have resulted had the market been allowed to determine the allocation of resources – natural gas in this case. For any regulatory model to work effectively, therefore, regulators (governments) cannot mandate distribution targets. Forcing the LDC to connect non-economic customers adds to the burden of capital, raises the cost of service, and ultimately has a negative long-term net benefit.

The province has come to recognize that viability is tied to economic efficiency, not mandated delivery targets. On December 12, 2001, the province released *Seizing the Opportunity: Nova Scotia's Energy Strategy*, which among other things reversed the previous policy of mandated distribution targets for natural gas. The strategy states, "To encourage the construction of a viable natural gas distribution system, pipelines will now be built where and when it makes economic sense to do so" (Nova Scotia, 2001b).

The PB model proposed by Sempra is more sensitive to capital costs than the CoS model. In an effort to minimize capital costs, the company requested approval to lay pipe along existing transportation corridors. It argued that the practice is allowed in other jurisdictions across Canada. The province disagreed.

[24] These agreements are often foundational in the building of lateral pipelines, and without them some laterals would not be built. In *Seizing the Opportunity: Nova Scotia's Energy Strategy,* the province confirmed that it "will continue to support further use of the Maritimes and Northeast Pipeline Inc.'s laterals policy" (Nova Scotia, 2001b).

[25] The detailed arguments for and against the use of industrial bypass agreements are technical and complex. Although they are beyond the scope of this paper, an overview of these arguments is presented in Appendix 1 of this paper.

Across Canada, low-pressure pipe is commonly laid along and under existing roads and highways; this *is* allowed in Nova Scotia. However, medium- and high-pressure pipe is *not* – in any jurisdiction in Canada – except where there is no other option, such as where terrain would prohibit or totally render impractical the laying of pipe outside an existing highway right-of-way.[26] Sempra argued that there was no other practical option other then to lay medium- and high-pressure lateral pipe along highway rights-of-way. The province disagreed that the terrain justified such a move and denied the company's request. In short, Nova Scotia was using similar criteria to other jurisdictions, and Sempra was requesting special consideration.

Nonetheless, the primary issue in Nova Scotia for Sempra was the mandated target for gas delivery, which has now been abandoned.

Summary – Atlantic Canada

So what have we learned?

- Unbundling of services in a greenfield market has slowed the development of the gas market and negated the incentive offered by a 30 percent price discount for households.
- Past policies, which subsidized taxpayers to switch from oil to electricity, will harm the development of the gas market.
- Ignoring economic forces and mandating market targets distorts the market and ultimately produces fewer jobs and benefits than if market forces determined when and to whom gas becomes available.
- Industrial bypass agreements can create cash-flow problems for LDCs, but they can also bring gas to large clients and markets that otherwise might not be served.
- Industrial bypass agreements should be used only when the benefits outweigh the negative impact on LDCs.
- It is not clear from Sempra and Enbridge Gas New Brunswick's experiences whether the cost of service model or the performance-based model is the most appropriate for launching a gas system in a greenfield market

[26] Discussion with officials at Energy Probe and the Alberta Energy and Utilities Board confirm that medium- and higher-pressure gas lines are not allowed along existing transportation corridors unless there are exceptional circumstances.

Recommended Regulatory Regimes and Policies

We now have enough background and information to outline what policy and regulatory structure would work best in Atlantic Canada.

Policy Considerations

As an overriding consideration, governments must work cooperatively to enhance the size of the economic and social benefits pie rather than each focusing on how to protect its turf and get a bigger piece of a smaller pie.

Benefits aren't seen in the same light by all levels of government, which unfortunately tend to see benefits based upon their ability to carve out a piece of the pie. Such a balkanized view leads to poor and shortsighted policies. When they don't work cooperatively, the ground is fertile for counterproductive policies and regulations.

Benefits from natural gas are not synonymous with use or consumption. Even if Atlantic Canadians never choose to hook up to their own natural gas, the royalties, economic growth, economic diversification, and a new addition to the energy mix will generate benefits far greater than those that could come from local consumption alone. The creation of an industry that discovers, produces, and delivers natural gas to market should be viewed as the most significant benefit, with the availability of gas for local consumption as a valued by-product.[27]

In this light let's first look at what governments shouldn't do.

[27] Benefits also come from selling one asset (gas) and using the proceeds to build other assets, such as hospitals, roads, and schools. Unfortunately, provinces like Nova Scotia and Newfoundland and Labrador get to keep only a fraction of the revenue from the sale of oil and gas resources. Under the Equalization formula the federal government does not treat oil and gas assets as it does other assets; it claws back royalties as long as a province is receiving Equalization payments. The negative effects of this "welfare trap" and why revenues from the sale of an asset should not be included in the Equalization formula are well documented by Kenneth Boessenkool (2001) in a recent AIMS publication.

What Not to Regulate

Regulations are required where markets fail or where there is a possibility of major market distortions or where externalities such as health and safety and pollution are not accounted for. The guiding principle should be to have the minimum level of regulations necessary to protect consumers, while ensuring the integrity of the gas distribution system. In this context the following points outline three policies or regulatory actions that would have a negative impact on gas distribution regardless of the regulatory framework adopted by provincial governments:

- Regulators (governments) cannot mandate distribution targets. Being forced to connect non-economic users adds to the burden of capital, raises the cost of service, and ultimately has a negative net benefit. Regulators and governments should allow the LDC to determine who is connected and how fast the system is extended, so as to maximize the benefits of gas for the region as a whole, and not just for specific individuals who happen to get hooked up. It is in the interest of LDCs to provide gas to the maximum number of consumers at the lowest price determined by the market. In so doing they maximize their profits. Regulations and policies don't outperform these market incentives.

- Regulators should not dictate the discount rates adopted by LDCs. LDCs should determine the most appropriate discount rate (price of gas as a percentage of home heating oil) to build markets. Discounting is required to build markets, and higher volumes lower the cost of service per unit of gas delivered, which drives LDCs toward the point of profitability. Therefore, it is in the interest of LDCs to discount to gain market share. This does not need to be regulated.

- Regulators should not preclude the LDC, which is building the distribution system, from marketing gas (signing up new customers). Separating marketing of gas from distribution (unbundling) and preventing the LDC from marketing gas makes no economic sense and more than likely is a major contributor to the slow penetration of the gas market in New Brunswick. While the unbundling of service has economic rational in a mature market, it is a deterrent in a greenfield market.

Recommended Regulatory Framework

The question in Atlantic Canada is, What is an appropriate regulatory framework for gas distribution when the industry is in its infancy? At the inaugural stage of the gas industry – apart from the government's choosing a distributor (LDC) – provincial regulations specific to gas distribution are not required. Monopoly or market power is non-existent for the industry at its launch. Health and safety, workplace, and environmental concerns are not industry specific and are dealt with through existing general laws and regulations. There is therefore no compelling rationale for regulating the industry at its inaugural stage. The most desirable approach would be for the regulator to choose an LDC and let it get on with the business of building the distribution system. The regulator can play a monitoring or oversight role to insure that the LDC continues to act in the public interest. As LDCs gain market share

and market power (i.e., if and when market distortions become a factor), regulations can be added as needed to protect public interest and ensure the integrity of the system.

Nonetheless, governments have a propensity to regulate, often as a form of insurance that the public interest is being protected. As a next-best option to a hands-off policy of market-driven efficiency, provincial regulators may choose to approve a cost/pricing model by which they can monitor performance of LDCs over time.

Building distribution infrastructure from scratch involves a massive up-front investment with a sizable risk. Until the market is really known, LDCs are only guessing as to the volumes, rate of growth, and number of customers. The cost of service (CoS) model is widely used across Canada, but is being re-evaluated in mature markets such as Alberta.[28] Deregulation of the industry in North America has resulted in a move away from CoS toward a performance-based (PB) model.

Nonetheless, the CoS model would on balance be the most appropriate framework for an emerging industry. It should, however, be up to LDCs to propose to regulators which model they prefer. The risk is being assumed not by the regulator but by the LDC and its investors. As such, the LDC should determine how much risk it is willing to assume and whether it is willing to accept higher short-term risk for potential long-term higher returns (PB model) or to use a CoS model, which flattens out the risk-return curve.

If the CoS model is chosen, it should be in place just long enough to

- build market share to the point where the cost of service is lower than the discounted price of gas,
- generate revenues sufficient to recoup initial losses plus interest on those losses, and
- cover (amortize) the majority of capital costs of the initial infrastructure.

Once this point is reached, the regulatory framework should move to a PB model. A model similar to the Retail Price Index plus or minus an efficiency factor, used in the UK for electrical utilities, would be the recommended approach. This system, unlike the CoS, is designed to allow LDCs to realize some of the benefits from system efficiencies. They get to keep the profits from system efficiencies for a period. Regulators periodically adjust the efficiency factor *X* to squeeze out excess profits, for the benefit of consumers. Between "squeezes" (while *X* remains unchanged) LDCs benefit from the efficiencies they generate. The regulators' principal responsibility is to set an efficiency factor that ensures that profits are maintained at a sufficient level to maintain the long-term viability of the system.

[28] Alberta has begun to deregulate the commodity portion of the industry. However, the major increases in gas prices over the 2000/01 heating season have generated debate over which regulatory model is the most appropriate. John Nichol, executive manager of surveillance and enforcement, Alberta Energy and Utilities Board, indicated in a telephone discussion that Alberta is reviewing the impact of deregulation on the industry in North America with respect to Alberta and looking at regulatory models other than cost of service.

Once Atlantic Canada's distribution system and market is mature, governments can look at the lessons learned from unbundling services in North America and look at unbundling services in Atlantic Canada where appropriate.

The recommended regulatory model and accompanying policies, by harnessing competition and market discipline, will help ensure that the maximum number of Atlantic Canadians have access to natural gas at the lowest possible price. However, competitive forces cannot guarantee that the gas market will grow rapidly – only that it will grow efficiently. Governments will therefore have to resist politicizing the regulatory process for the purpose of encouraging rapid access.

Appendix 1: The Impact of Industrial Bypass Agreements

An industrial bypass agreement is an agreement directly between a large industrial user and the transmission company (Maritimes & Northeast Pipeline). Such an agreement usually involves the construction of a lateral pipeline connecting the industrial client to the main transmission pipeline.

The load of a large industrial user is known, immediate, steady, and large, while the load requirement for a multitude of households and commercial users is not as certain, and it builds over time. A local distribution company (LDC) will normally blend these loads to spread out costs and improve cash flow. The removal of a large, steady-volume (anchor-load) customer through an industrial bypass agreement with Maritimes & Northeast Pipeline (M&NP) means that the anchor-load user gets gas directly from the transmission company and therefore saves the distribution charges that would have gone to the LDC.

To date, the National Energy Board (NEB) regulates the lateral lines serving bypass customers. The cost of service on these laterals is rolled into the cost of service for the entire transmission system and is therefore reflected in the transmission toll paid by all customers (postage stamp toll charge). M&NP applies a lateral test to determine if the toll on the lateral justifies building the lateral. If the lateral will add significantly to the overall system toll, M&NP can decline to build it or it can require the anchor-load client to pay a portion of construction costs, thereby reducing the impact of the lateral on the overall toll. When approving a lateral, the NEB approves a line capacity sufficient to serve the expected needs not only of the bypass customer but also of the surrounding community. The cost of servicing this extra unused capacity is factored into the toll and is paid by existing customers.

The bypass option allows anchor-load users to avoid the distribution charges by contracting directly with the transmission company. Because of the volume of energy used, large users are very sensitive to energy costs, and they receive favourable energy prices from suppliers. The saving of the distribution charge is often a critical factor in tipping the scales in favour of switching to natural gas. Therefore, the bypass option attracts to the system some large-volume clients that would not otherwise be consumers of gas.

LDCs rely on anchor-load customers to help balance the annual fluctuations in demand from the space-heating segment of the market. Household and institutional users have cyclical demands, peaking in winter months and falling off to very low levels over the summer months. Losing anchor-load customers to the transmission companies can create major problems for LDCs. They are left with a very

high percentage of volume associated with customers whose gas consumption pattern fluctuates seasonally. LDCs contract for peak pipeline capacity to meet winter needs, and without anchor load customers, a much larger proportion of the distribution system remains idle over the summer months. This causes significant cash flow problems for LDCs. Therefore, "cherry picking" large-volume customers by the transmission company can hinder the economics of LDCs. As well, the loss of these customers means that the LDCs must rely heavily upon the space heating market.

Despite these drawbacks, by adding load to the system, laterals built to serve bypass clients can lower tolls and they can bring gas to areas that would otherwise not be served. In such cases the bypass client is the catalyst for opening a new market, which would be beneficial for the LDC.

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