
The natural gas industry has undergone dramatic change in the last decade as a result of deregulation. In this article, we consider the desirability of yet another innovation: the active use of natural gas futures and other financial derivatives by local distribution companies for price hedging purposes. Given the potential savings of short- relative to long-term contracts, the increasing security of supply, and the salient possibility of low (if not negative) costs in using these contracts, we argue that regulators should take a close look.

Au cours des dix dernières années, l'industrie du gaz naturel a subi des changements spectaculaires par suite de la déréglementation. Dans cet article, nous nous interrogeons encore sur l'utilité d'une autre innovation: l'utilisation active des opérations à terme sur le gaz naturel et de certains autres instruments financiers dérivés par les sociétés locales de distribution dans le but de couvrir les risques de fluctuation des prix. Compte tenu des économies potentielles réalisées à l'occasion des achats à court terme par rapport aux achats à long terme, de la sécurité croissante de l'approvisionnement et des chances importantes de générer des coûts modestes (sinon négatifs) en réalisant ces opérations, nous soutenons que les organismes de réglementation devraient y regarder de prêt.

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Should the Use of Hedging by Canadian Natural Gas Distributors Be Encouraged by Regulators?

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I. Introduction

Similar to other markets (e.g., airlines, telecommunications), the North American natural gas industry has been partially deregulated since the mid-1980s. In October 1985, the Federal Government signed the Agreement on Natural Gas Markets and Prices (The Western Accord) with the governments of British Columbia, Alberta and Saskatchewan. The objective of the agreement was to end regulation of wholesale natural gas prices and to create a competitive market for gas where buyers and sellers could freely negotiate prices. The new market system that emerged replaced an old system in which buyers had very few choices regarding sources of supply, transportation arrangements or prices. In the old system, end users purchased natural gas from local distribution companies (LDCs), with prices and terms based on agreements between the Government of Alberta and the Federal Government, and on regulatory decisions by the National Energy Board (NEB) and provincial regulators such as the Ontario Energy Board (OEB), which affected the price of gas and transportation, distribution, and

storage costs.¹

The deregulation process in Canada paralleled a similar process in the US where gas buyers and sellers have been able to conduct direct commercial transactions since 1983, when the Federal Energy Regulatory Commission (FERC) issued Orders 319 and 234B. Together with other decisions by the US Court of Appeals for the DC Circuit, these directives led to open access on interstate pipelines. This in turn fostered independent trading of natural gas supplies, often in short-term contracts rather than the long-term contracts involved in traditional pipeline sales. US LDCs have not been required to purchase any gas at all from their pipeline suppliers since the issuance of FERC Order 380 in 1984. This rule effectively created a new market for gas supplies to the LDCs. Interstate pipelines must transport gas on a non-discriminatory basis. Space on pipelines became a commodity separate from natural gas itself.

As a result of the deregulation process, a competitive commercial environment in the North American gas market has been created. The price of a cubic foot at the margin is now determined freely by market forces. Buyers must decide how best to benefit from a competitive supply of natural gas, and be prepared to assume the risks associated with those decisions. In fact, in a recent study of future energy demand in Canada, the NEB states that its projections of natural gas prices are developed "... on the premise that Canada participates in an open, integrated and competitive North American natural gas market, in which North American supply and demand conditions determine the prices of natural gas in Canada and the US" (National Energy Board, 1991, p.111).

The objective of this paper is to describe recent changes in the North American natural gas market and the impact of these changes on pricing and contracting practices in the industry. In particular, because the increased importance of short-term contracts heightens the exposure of market participants to price risk, it is suggested that natural gas distributors, regulators and others involved in

the Canadian gas sector should take a closer look at how newly emerging financial markets offer an alternative vehicle for reducing price risk. The existing natural gas futures market and the more recently opened market in options on natural gas futures in the fall of 1992 provide the gas industry with a variety of risk management tools previously unavailable.

Section II describes the effect of deregulation on the North American natural gas market. In Section III it is argued that a continuous increase in pipeline capacity has guaranteed security of supply, once a formidable problem faced by LDCs. The specific characteristics of the natural gas futures market are explored in Section IV, while Section V considers whether an LDC can truly hedge. Some policy recommendations and conclusions are offered in Section VI.

II. Impact of Deregulation on the Canadian Natural Gas Market

"Deregulation in October, 1985 did not change the flow of gas from the western provinces into Ontario. The structure of ownership of the processing plants, gas pipelines, and distribution systems also remains the same" (Ontario Ministry of Energy, 1988). The contractual arrangements within the industry, however, have dramatically changed. Deregulation has led to an increase in the number of buyers and sellers of Canadian gas in both domestic and export markets with contract terms and prices varying widely.

The Natural Gas Price Monitoring Report (EMR Canada, 1991 and 1992) documents developments in the Canadian gas market, export and domestic, during the 1989/90 and 1990/91 gas years.² It divides exports and domestic gas sales into three categories.

- Long-term firm — applies to the gas supply arrangements of domestic LDCs, US importing LDCs, marketing agents, and

1/ Natural gas prices were linked to crude oil prices.

2/ The 1989/90 Canadian gas year is defined as the period November 1989 through October 1990.

pipelines with contract terms exceeding two years.

- Short-term firm — applies to contracts with terms of up to two years, and encompasses most of the "direct sales" of Canadian gas to domestic or US buyers.
- Interruptible sales — typically refers to sales of gas on a monthly spot basis.

One can clearly observe (Table 1) a continuous increase in short-term gas flows (i.e., short-term and interruptible sales) and a reduction in the number of long-term contracts. During the period 1986/87 to 1990/91, long-term sales fell from 87.8 to 51.3% of total domestic sales in Alberta and from 77.4 to 73.1% of total domestic sales in BC, respectively. During the same four-year period, a similar trend occurred in the export market where long-term sales declined from 94.2 to 62.5% in Alberta, and from 45.9 to only 17.8% in BC.

The same trend is observed in specific contracts. For example, sales by Alberta and Southern Gas Company Limited (A&S) to Northern California were down 15% during the 1990/91 contract year compared to the year before. In contrast, interruptible volumes increased by 482%, indicating that spot sales have displaced this firm A&S gas.

The move towards short-term and interruptible agreements has been accompanied by a continuing decline in North American natural gas prices. The decline is linked to recessionary factors, relatively warm weather, and slow storage injection rates. During the 1991 calendar year, spot gas prices reached their lowest level since deregulation, with 1991 Alberta border prices averaging C\$ 1.15/GJ, and US spot prices averaging US\$ 1.40/MMbtu. Because firm gas accounts for a high proportion of gas exports, export prices were slow to adjust. In fact, during the calendar year 1991, long-term export prices rose by C\$.02/GJ. The average price for short-term export sales, however, fell by approximately 11%, mirroring the US spot price plunge.³

As seen from the information provided in Table 2, the average price on the ANR line has

declined by over 20% from US\$ 1.88/MMbtu in 1990 to US\$ 1.44/MMbtu in 1991. Similar price declines have been observed on other lines where prices in some places have declined below US\$ 1.00/MMbtu.

The most important impact of the price decline is the widening of the spread between spot gas and long-term contract prices. The average spread between Alberta spot and long-term prices of gas sold to eastern Canada is close to C\$.80/GJ. This has forced gas buyers to reevaluate their acquisition strategies. The recent debate over Alberta gas sold to California highlights this point. It is quite clear that California is determined to pay the lowest prices possible even if this entails the violation of signed agreements. The A&S supply pool of 190 producers provides approximately 40% of the PG&E's daily demand. The availability of alternative supplies and lower spot prices has put pressure on Alberta to lower its prices. Thus, the price received by A&S for Alberta gas shipped to California has been renegotiated. Prices were reduced by 16% from the original US\$ 1.80/MMbtu to an average of US\$ 1.55/MMbtu and an access agreement was signed to free capacity for direct sales to California consumers. As well, in November 1991, California announced its move towards capacity brokering commencing October 1, 1992. This announcement negates the access agreement, but also claims to void all previous contracts with A&S. Clearly, these moves had an impact on the recently signed agreement between A&S and its suppliers. The new contract guarantees a basic volume of 212 MMcf/day at a price of US\$ 1.52/MMbtu. Sales of additional volumes are to be indexed to market prices in the US (Motherwell, 1992).

California's attempts to replace the A&S contracts with direct sales notwithstanding, it is likely that a concession such as the one

3/ Other long-term factors have also contributed to this decline in price. For example, lower export prices in BC can be, at least partially, attributed to the abandonment of price restrictions by the BC government in November 1990, allowing producers to price their gas more competitively.

Table 1: Domestic and Export Quantities at the Alberta and BC Borders

Year	Long-Term Firm (%)		Short-Term Firm (%)		Interruptible (%)		Total (PJ)	
	Export	Domestic	Export	Domestic	Export	Domestic	Export	Domestic
Alberta								
1986/87	94.2	87.8	.009	5.4	4.9	6.8	837.4	1298.0
1987/88	81.4	73.5	11.5	14.9	7.0	11.7	1189.9	1424.8
1988/89	80.0	63.6	11.0	27.5	9.0	8.9	1223.9	1469.4
1989/90	72.7	60.7	13.5	32.7	13.8	6.5	1348.3	1401.0
1990/91	62.5	51.3	14.7	37.2	22.8	11.5	1509.5	1339.1
British Columbia								
Year	Export	Domestic	Export	Domestic	Export	Domestic	Export	Domestic
1986/87	45.9	77.4	n/a	12.6	54.1	10.0	113.1	214.8
1987/88	30.8	67.4	1.7	14.3	67.5	18.2	122.8	240.2
1988/89	4.9	75.8	95.1	24.2	n/a	n/a	110.6	258.1
1989/90	8.7	74.5	41.0	11.2	50.3	14.3	170.4	249.0
1st Half 1990/91	17.8	73.1	49.3	15.2	32.8	11.6	114.9	159.1

Source: *Natural Gas Price Monitoring Report*, various issues.

described above for sales to California will be granted for the remaining life of other contracts. This in turn will put pressure on small independent producers to lower their prices in order to be competitive in the export market.

The California experience is not unique. As a result of the opening up of new markets through transportation expansion, competition from alternative fuels, and the resulting price declines in the spot market, the difference between what buyers are paying now under their long-term contracts and the prices available in the spot market has increased. Since the cost of complying with these contracts has risen, it is quite likely that many buyers will seek to reopen them through renegotiation, or will try to find other means to mitigate the high prices. These will most likely result in a further decline in average prices.⁴ Further, many buyers are likely to reduce their rate of take and will use the spot markets at lower prices. The result of such practices may be that suppliers will feel the pressure to either

renegotiate long-term contracts into shorter term deals at lower prices, or lose their buyers. Newer contracts, however, are likely to reflect the trend toward shorter term obligations only if a reasonable stability of supplies can be assured. The recent and planned pipeline expansion will provide this assurance.

III. Is Security of Supply a Problem?

Pipeline construction in recent years has set the stage for secure natural gas deliverability in North America. It is estimated that the dollar value of pipeline construction commenced in 1990/91 is in the range of \$US 11.5 billion. It is also predicted that there will be pipeline construction far into the future.

4/ For example, in July 1992 the pool of 190 Alberta producers signed a new pricing contract with Consumers' Gas Co. Ltd. of Toronto. In a two-tiered deal, they agreed to an average price of C\$ 1.59/GJ, down from C\$ 1.91/GJ in the previous contract.

Table 2: Sample of Gas Daily Monthly Contract Index Prices

Month	Locations			
	Louisiana Onshore South ANR	Oklahoma PEPL	New Mexico San Juan Basin El Paso	North West SUMAS
May/90	1.43	1.28	1.45	1.16
Jun	1.46	1.28	1.47	1.16
Jul	1.43	1.26	1.44	1.17
Aug	1.35	1.23	1.43	1.12
Sep	1.37	1.26	1.41	1.16
Oct	1.55	1.43	1.65	1.28
Nov	2.03	1.77	1.92	1.61
Dec	2.33	1.92	1.94	1.65
Average	1.88	1.48	1.67	1.35
Jan/91	1.85	1.61	1.80	1.80
Feb	1.32	1.26	1.26	1.68
Mar	1.32	1.24	1.04	1.12
Apr	1.32	1.23	1.05	1.03
May	1.30	1.23	1.07	1.01
Jun	1.27	1.20	1.07	1.01
Jul	1.10	1.08	1.02	0.95
Aug	1.12	1.09	1.08	0.98
Sep	1.33	1.26	1.18	1.08
Oct	1.69	1.58	1.40	1.23
Nov	1.76	1.63	1.61	1.24
Dec	1.87	1.78	1.81	1.54
Average	1.44	1.35	1.28	1.22

The Monthly Contract Index is a weighted average cost of gas per MMBtu based on volumes and prices for spot deals consumed during the week prior to and including pipeline nomination days.

Source: *Gas Daily* (various issues).

Two main factors affect pipeline construction in Canada. The first is the relaxing of constraints on Canadian exports. As a result, the majority of the recently built/proposed pipelines is for increased exports of Canadian gas; e.g., Iroquois, TCPL, Niagara Import Point Project, Great Lakes,

PGT/Altamont, and Empire.⁵ The second factor is the existing capacity constraints in various regions of the US (e.g., California, the northeast).

In the US, flow patterns currently run in a southwest to northeast direction. The south central region, still a prominent player in today's gas supply (70% of supply in the lower 48 States) feeds into the whole northeast and eastern coastal regions. There is, however, very little east-west flow, except for the current flows of gas to California from the Gulf and the recent expansions to carry gas from the Rocky Mountains and the San Juan Basin. Canadian gas accounts for some north-to-south movement and into the Pacific northwest, mid-continent, and northeast. A recent development in BC falls outside the general patterns. Some gas is to be imported from the US through Sumas, Washington. BC Gas has proposed to build a short pipeline to bring 350 MMcf/day of US spot gas to BC residents. Cheaper supplies and avoiding increased transportation charges have been cited as reasons for the project.

Gas demand growth in various regions is directly related to improved deliverability due to pipeline construction. Current and proposed pipeline expansions into California, the northeast, and the mid-continent regions will significantly contribute to the growth in these regions. The majority of growth in demand (about 60% of incremental demand) is expected to come from gas-fired power generation concentrated in the eastern US. This will help assure that west-east flows will increase in importance. The source of this supply, however, will probably change, bringing about a flurry of new pipeline development. The importance of the Gulf area as a provider of the majority of US gas will diminish over the next 20 years (an expected decline of 15%). This will mainly impact deliveries from the gulf to the mid-continent, California, and the northeast regions (given the natural tendency to concentrate on deliveries

5/ By 1995, Canadian export capacity will have increased by 1 Tcf.

to closer areas). In California, the decrease in supply will be made up by deliveries from Canada and the San Juan basin. Canadian exports will probably replace some of the supplies to the northeast, and gas from the Rocky Mountains will probably supplement Canadian exports to the mid-continent region. The decrease in gas flow to the northeast from the Gulf region is of importance to Canadian exporters, importers, marketers and LDCs. By the year 2010, Rocky Mountain gas will likely be an important US source. Since the shortest distance from the Rocky Mountains to the American northeast is through Canada, gas from the Rocky Mountains could, therefore, flow through southwest Ontario for re-export.⁶

The drop in export and domestic prices during the years following deregulation have a serious impact on long-term contracts. Many of these long-term contracts were signed during the period when security of supply was a major concern. Buyers were willing to lock into contracts at higher prices for assurance that the supply would be there. As argued above, security of supply is no longer an issue to the same degree that it once was. Buyers will most likely be willing to sacrifice that security to take advantage of lower short-term prices. In the future, however, Canadian buyers, including LDCs, may have to rely on acquiring shorter-term, cheaper gas from markets such as the US.⁷ In short, from a market dominated by long-term contracts and stable prices, the North American market has evolved into a dynamic, highly competitive market with flexible pricing in an active spot market. A tool for the management of increased uncertainty and price risk is thus required. As argued below, regulators should rethink their position regarding the utilization of futures contracts, taking into account the possibility of using this alternative insurance mechanism to replace long-term contracts.

IV. Special Aspects of Natural Gas Futures⁸

The changes occurring in the North American natural gas industry have attracted the

attention of participants in financial markets. One reaction has been the launching of a natural gas futures contract (on April 3rd, 1990) on the New York Mercantile Exchange (NYMEX).⁹ Unlike many other new contracts, the natural gas futures contract was an immediate success. Volume and open interest have been distributed throughout the twelve listed months since the start of trading in April 1990. In 1991, for example, 315,026 contracts were traded. On the surface, this might indicate an industry reliance on this contract as a long-term risk-management tool. NYMEX reacted by extending the maximum maturity of the contract. It has now been listed for 18 months, instead of 12 months, as of January 27th, 1992. Furthermore, in the fall of 1992, trading began in options based on the natural gas futures contracts.

The success of the futures contract may be attributed to two factors:

- The natural gas market involves most, if not all, of the general characteristics of a successful commodity futures contract.
- NYMEX has altered the basic futures contract to reflect the specific characteristics of the natural gas market.

A number of fundamental characteristics are generally shared by all successful

6/ With all the activity proposed in the future to transport gas across North America, development on a smaller scale will also occur to accommodate this flow. Regional infrastructure will be developed to allow for the distribution of this gas to growing regions off the main transmission system.

7/ Although US transportation tolls are now generally less than Canadian, the higher priced US gas offsets any advantage that may be gained by buying in the US. In the future, increases in Canadian transportation cost (tolls) accompanying expansion of the transportation facilities (e.g., NOVA, TCPL) might erode the benefits of buying in Canada.

8/ For a detailed explanation of various hedging techniques and for tests of hedging effectiveness, see Deaves and Krinsky (1992b).

9/ For contract definition, see notes to Table 3.

commodity futures contracts. They include: an active, volatile spot market for the commodity which will stimulate hedging demand, commodity fungibility, free market pricing, and a viable delivery mechanism. Some, though not all, of these are found in the NYMEX natural gas futures market. In particular, the delivery mechanism may appear, at least on the surface, to be problematic. This is a result of the special characteristics of natural gas as a commodity and the nature of the industry:

- producing and consuming regions are spread across the continent and different regions have different supply and demand characteristics; and
- the cost of transportation differs between the various sending and receiving points.

A viable mechanism to assure that deliveries are made in fulfillment of futures obligations ensures a direct connection between futures and cash markets, specifically with regard to the convergence of their prices as the futures contract expires. The natural gas contract delivery mechanism has been developed utilizing Sabine Pipe Line Company's Henry Hub in Louisiana, a gas interchange in operation since May 1988. There are, however, a limited number of interstate natural gas pipelines that connect to the Henry Hub. Thus, the convergence problem has been the prime concern of both the Exchange and market participants.¹⁰

An important factor which has skewed the statistical comparison between futures prices and cash prices even at the Henry Hub in Louisiana is the convergence problem caused by the time lag between the expiration of the one-month futures contract and the trading of the cash market for that month. Typical gas spot market arrangements involve one month flows under separate transportation arrangements with one or more pipelines. Pipelines require shippers to indicate their need for (nominate) capacity five to eight days before the end of the month preceding the 30-day period when their gas will flow. This timing usually causes a mini-frenzy known as "bid week" when marketers and gas producers,

among others, compete to put deals through for the next month's gas supplies. When the natural gas futures contract was launched in April 1990, contracts expired on the eighth business day before the first day of the delivery month. Thus, there was a difference of up to three days between the expiration date of the one-month future contract and the beginning of nomination week. During this period, cash, but no futures, transactions were taking place.

As a partial solution to the problem, on March 28, 1991 the Commodity Futures Trading Commission (CFTC) approved the application by NYMEX to extend trading by one day each month. Thus, instead of terminating on the eighth business day before the first day of the delivery month, starting with the May 1991 contract, trading ceased on the seventh business day in advance. A further extension of trading by one day took place beginning with the October 1991 contract. The purpose of these amendments is to allow market participants to take into account changes in pipeline nomination information and deadlines of pipelines interconnecting with the NYMEX delivery point at Henry Hub. Figure 1 shows the trend, over the past year, in the difference between the closing price of gas futures traded on NYMEX and *Gas Daily's* price of gas sold on the cash market at Henry Hub. The chart indicates that the severity of the convergence problem had been substantially reduced toward the end of 1991.

An additional factor specific to natural gas futures contracts relates to the price paid for natural gas delivered into each pipeline. These prices have a unique "basis" or relationship to the natural gas futures price which fluctuates over time. The difference between the prices on the various pipelines and the futures price is what is commonly referred to as location basis. These fluctuations may be caused by a number of variables, including rate changes, capacity constraints, varying seasonal loads, and other demand/supply conditions unique to a particular pipeline. One can clearly

10/ See, for example, O'Reilly (1991), pp.6-7.

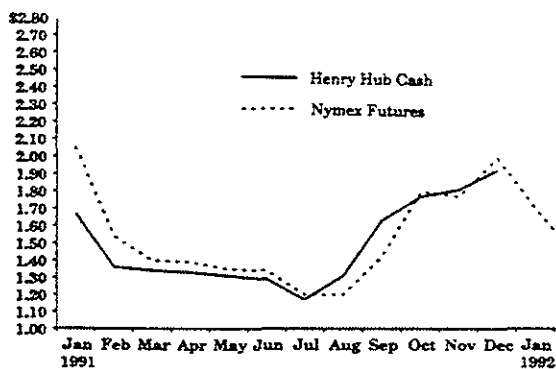


Figure 1: Spot/Futures Price Comparisons

observe in Figure 2 that the further away the location is from the Henry Hub, the larger is the basis.

In order to partially overcome the location basis problem, the Exchange has introduced an alternative mechanism to enable users to purchase or sell gas at locations other than the Henry Hub. The mechanism is known as the "exchange of futures for physicals" (EFP). The EFP transaction allows a buyer or seller to exchange a futures position for a physical position outside the Exchange's standard delivery mechanism. With an EFP, buyers and sellers can negotiate the terms of delivery for the physical transaction including the price, location and timing of physical delivery. Under the EFP transaction, which liquidates open futures positions, margin funds are released upon notification of the transaction, and, unlike Exchange guarantees under standard delivery procedures, the physical transfer and payment is not guaranteed by the Exchange. The process thus expands the range of trading partners outside of those actively using futures to include those trading in cash markets in many locations. Obviously, an important contribution of EFPs is their effectiveness in increasing the liquidity of natural gas futures. The data presented in Table 3 are EFPs transacted during the spot month and until 2pm on the business day following termination of contract trading. (EFPs for non-spot contracts are not included

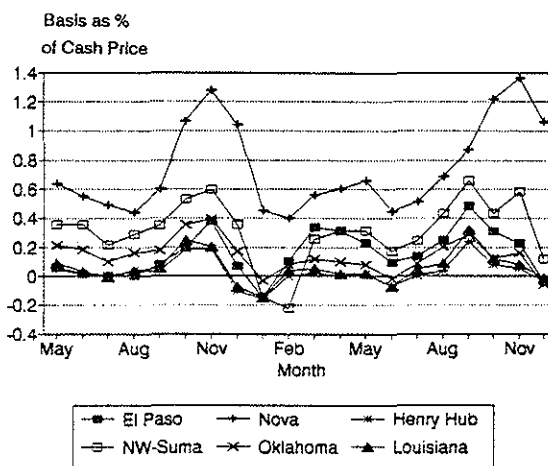


Figure 2: Spot/Futures Comparison — The Location Basis (May/90 to Dec/91)

Source: *Gas Daily*, 1990 and 1991 annual price issues.

in these data.) One can see that, during 1990, 60% of deliveries were attributed to EFPs and that this fraction remained fairly constant in the first two months of 1991.

With the advent of natural gas futures trading, one should expect to see the growth of derivative hedging products that allow market participants to hedge without taking a contract position in the futures market. Such hedging products are currently offered by either marketing companies or financial intermediaries. As noted above, NYMEX has introduced options on natural gas futures. This product supplements both natural gas futures traded on NYMEX and options on spot natural gas which are currently sold by marketers to producers and some LDCs in the US.

V. Should Regulators Encourage Hedging?

The current environment is witnessing a gradual move from long-term to short-term contracts. The recently signed contract between A&S and PG&E, for example, illustrates that even long-term contracts may include a short-term pricing component. Given this, why has

Table 3: NYMEX Natural Gas Deliveries

Contract Month	Standard Deliveries (Excluding ADPs/EFPs)	ADPs	Total EFPs	Total Deliveries	Trading Volume (Number of Contracts)	Deliveries / Cumulative Trading Volume (%)
Total 1990	735	182	1,384	2,301	56,747	1.62
Total 1991	2,034	415	9,442	12,161	315,026	0.86
Jan. 1991	171	57	439	667	25,363	0.90
February	250	21	242	513	29,926	0.91
March	254	66	466	786	19,426	1.65
April	90	54	577	721	13,612	1.06
May	100	11	348	459	14,262	0.78
June	105	-	551	656	16,543	0.63
July	144	-	724	868	15,820	0.91
August	157	16	741	914	21,193	0.82
September	218	20	1,261	1,499	28,694	0.83
October	248	85	1,195	1,528	33,117	1.01
November	192	60	1,251	1,503	35,471	0.71
December	375	25	1,647	2,047	61,599	0.65

Notes and Definitions:

ADPs = Alternative Delivery procedures which are performed subsequent to the termination of trading in the spot-month contract. In an ADP transaction, the buyer may agree with the seller with whom he has been matched by the Exchange to take delivery under terms or conditions which differ from the terms and conditions prescribed by NYMEX contract rules. In such transaction, the Exchange must receive a notice from Clearing Members handling the accounts of ADP parties.

A NYMEX natural gas contract represents 10,000 MMBtu. Therefore, total 1990 deliveries of natural gas (2301 contracts) is equal to 23.01 trillion Btu or approximately 23 Bcf.

Trading Volume = Cumulative number of trades in each contract month, beginning with the first listing of the contract and ending with the termination of trading in that contract.

Deliveries as a % of Cumulative Trading Volume include standard deliveries and ADPs only.

Source: *Energy in the News*, various issues.

the practice of hedging not been adopted in Canadian gas transactions? It is our view that the regulatory environment is not conducive to hedging activity. The current practice in many Canadian jurisdictions (e.g., Ontario) involves the direct shifting of price risk from LDCs to ratepayers. This is due to a regulatory mechanism called a deferral or variance account, which allows the LDC to debit or credit this account based on the actual versus forecast gas price variance. The accumulated benefits or costs in the variance account are passed on to the ratepayers at the end of the fiscal year. The LDC bears risk only to the

extent that gas prices rise above those of alternative fuels and, thus, market share is lost.¹¹ A question for regulators, as well as consumers and LDCs, is whether such an approach constitutes appropriate public policy. While that is a larger issue than can be approached in this paper, there is a case to be made for the LDCs' use of hedging through the gas futures market even with this arrangement for risk sharing.

11/ We would like to thank an anonymous referee for bringing this point to our attention and for providing the explanation cited above.

Recall that one of the main purposes of futures markets is the shifting of risk to intermediaries that specialize in such a function. On the surface it might seem that the benefits to ratepayers from LDCs' utilization of futures contracts will be outweighed by the premiums associated with futures contracts. One should remember, however, that premiums are paid even under current contracting practices. In Quebec and Ontario, for example, LDCs purchase most of their gas requirements through short and long-term contracts at prices which are directly negotiated between the LDC and the supplier. The prices are constant for 12 months at a time. Clearly, these prices embody risk premiums (i.e., an insurance premium) which might be above or below the risk premiums in competitive markets (e.g., the futures market). Furthermore, it is not clear *a priori* that the process of risk transfer through participating in futures trading will entail a cost in any case; that is, the premium might be zero or negative.¹²

The latter point requires further explanation. "Long hedgers" (such as LDCs that are purchasing gas) will face the cost of risk premiums only if futures prices correspond to the pattern known as "contango." Risk premiums may, however, be *negative* if a "backwardation" pattern of futures pricing exists. An illustration will clarify the meaning and relevance of these terms. Suppose that the only entities interested in using the natural gas futures market for hedging are long hedgers. These parties are interested in buying futures contracts in order to protect themselves from rising product prices. Who will take the other side in these trades? If trades take place at futures prices equal to the average expectation of the eventual cash price, the answer is virtually nobody. In order to attract traders into the market who are not interested in hedging, but in profiting from futures trading, long hedgers must offer prices higher than expected future cash prices. Since the futures price converges to the cash price by the end of the contract, the implication is that on average the futures price

will decline over the life of the contract. Only then will short speculators on average earn a profit from futures trading. Note that in this scenario the futures price exceeds the expected cash price. This gap should be viewed as a risk premium. The risk premium is an average reward for risk bearing that long hedgers cede to speculators who provide the valuable service of risk transfer.

The scenario in the previous paragraph specified that all hedgers were long hedgers. In reality, there is always a mix of long hedgers and short hedgers. The same argument will still apply, however, if there are more long hedgers than short hedgers. That is, hedging activity in the market is then "net long." This typical pricing pattern — that is, when futures prices are expected to decline over contract life — is known as "contango." On the other hand, if hedgers are net short (e.g., if the bulk of futures market participants are natural gas producers, which casual empiricism suggests might be the case), then futures prices will be expected to increase over contract life in order to compensate long speculators. This movement in futures prices is known as "normal backwardation."

If an LDC is on the "wrong" side of the market, the magnitude of the risk premium can be viewed as a cost of hedging. If contango applies, the LDC on average loses this premium by hedging. It believes that this loss is worthwhile for the risk reduction that it obtains. This situation can be viewed as being similar to the current practice in the industry in which the higher price paid by LDCs on long term contracts reflects a risk premium determined through direct negotiations between the parties. If, on the other hand, normal backwardation is observed in the natural gas futures market, the cost of hedging

12/ The following discussion focuses on risk premiums which are, potentially, the most important cost component when participating in futures trading. Hedging is also costly in the obvious sense that commissions and spreads (i.e., the difference between the bid and ask prices) must be paid. Futures commissions and spreads, however, are well-known for being quite low.

for LDCs may be *negative*. This will provide an "unexpected bonus" which cannot be obtained if current practices are to continue.¹³

The agencies which regulate LDCs must address two questions which relate to the safeguards to be instituted once LDCs are allowed to participate in futures trading. The first deals with whether or not potential activities of LDCs in futures or option markets should be considered as hedges. If the answer to the first question is in the affirmative, one must determine what treatment should be given to gains and losses associated with hedging transactions in gas futures or options.

It is important to remember that operating in the futures market in order to hedge is quite different from speculating in futures. Clearly, regulators would not condone speculation by public utilities. Hedgers are investors who plan to engage in a future sale or purchase of an asset and wish to reduce their uncertainty regarding the future price of the asset. In fact, a futures market will be active only if there is substantial price volatility in the commodity's cash market. If prices are stable over time, commercial interests would not need to use futures markets to transfer price risk, and there would be little interest from speculators who willingly accept risk in the hope of profiting from favourable price swings. The fact that there exists a market for natural gas futures can be viewed as an indication of substantial uncertainty associated with the future price of natural gas. (One can see this volatility in historical natural gas price data, as in Table 2.)

From a strict accounting viewpoint, it is clear that an LDC can qualify for hedging.¹⁴ Financial Accounting Standard Board (FASB) statement No. 80 in the US sets forth accounting standards for futures contracts. Changes in the market value of a futures contract must be recognized as a gain or loss immediately unless the contract qualifies as a hedge. To qualify as a hedge, the item being hedged must expose the enterprise to price risk. This test involves an additional complication in the case of an LDC because it buys gas on behalf of the final consumer (i.e., the price of gas paid for by the LDC is simply

passed through to the consumer with no mark-up, with the LDC's profit coming from supplying local transportation and related services). Thus, in a gas industry that uses short-term contracts, the "enterprise" is not exposed to price risk, but the final consumer for whom the LDC acts is exposed. In this sense, the LDC's commitments to purchase natural gas in the future involves a risk of loss that allows an offsetting futures contract to qualify as a hedge.

With regard to the second question of appropriate accounting, under the present practice of passing the LDC's purchase price through to the consumer, one would expect the regulator to require accounting rules which assure that the consumer pays the *net* price of gas. That is, hedging will typically involve a gain or a loss due to a difference between the price paid for the future contract when the hedging transaction was entered into and the spot price at the time of delivery. Suppose that an LDC purchases a two-month contract at \$1.20/MMBtu and that, when the delivery date arrives, the spot price has risen to \$1.40. The result is a net gain of 20¢ per unit.¹⁵ The regulator would require that the LDC claim

13/ Deaves and Krinsky (1993) provide convincing evidence of backwardation in the case of unleaded gas futures.

14/ See Appendix for a detailed description of the accounting treatment of futures.

15/ This gain appears to be a paper accounting calculation indicating the saving, relative to the observed spot gas price on the delivery date, that occurs because the LDC did not wait to buy the gas at the spot price. In fact, the typical case will involve actual cash flows. Instead of taking delivery on the futures contract (because, for instance, delivery is at an inconvenient location), the LDC would finally buy the gas on the spot market and cancel its original futures position by selling a corresponding futures contract at the going price, which will have risen along with the spot price. The profit on the futures transactions will bring down the net price of using the spot gas. (Of course, this illustration ignores various details which may mean that the realized gain does not amount to the full 20¢ per unit.)

only \$1.20/MMBtu. Suppose instead that the spot price had fallen to \$1.05. In this case the net price is still \$1.20, though it involves a net loss of 15¢ per unit.

One could imagine that a regulator might be tempted to treat this matter asymmetrically. It might want to require that all gains be passed on to the consumer, but be more suspicious of losses, perhaps subjecting them to a prudence test. The question of whether the LDC is effectively managing its hedging is, of course, legitimate, but is ultimately a difficult one to deal with. It has various aspects. At a mechanistic level, it is possible to establish and monitor accounting rules. But there is no absolute answer to the question of whether an LDC is acquiring the right amount of insurance; that is, whether it is hedging to the desirable extent. One expects that this has to emerge through experience, presumably by way of the regulator's monitoring of the gains and losses associated with particular transactions.

It is important to remember that this problem is not fundamentally different from the question of the desirable average length of contracts entered into in order to assure supply and protect the consumer from price increases. In both cases, the regulator has in principle to evaluate whether the gas consumer is being provided with enough protection at the lowest cost. The issue here is the choice of techniques used to provide that protection — hedging offers a useful mechanism to reduce the risk associated with short-term contracts that is not being used in Canada.

Finally, it is worth noting the views of someone who has examined the gas hedging question in the US. Ellis (1991) summarizes LDCs' involvement in the futures market from the perspective of the regulator as follows:

- Futures trading may be foreign to the regulatory process; however, this should not lead us to discard the market as a tool to obtain the lowest reasonable cost for purchased gas supply.
- The iterative process that has led LDCs to become aggressive gas supply aggregators may now require that the LDCs be more

than casual observers of the natural gas futures market.

- Similarly, just as state commissions have been forced to expand their expertise to evaluate the prudence of LDCs' purchasing practices, they will also have to expand their knowledge of the futures market.
- LDCs should initiate a dialogue with their state commissions on the status of the futures market in their planning.
- LDCs should be prepared to demonstrate the prudence or imprudence, both prospectively and retrospectively, of using gas futures to hedge their cash market positions.

VI. Implications for Regulation of Canadian Natural Gas Distribution

The natural gas industry has undergone historic changes in the past decade, and the use of futures may be the next logical step in the progression from a highly regulated to a competitive industry. With the recent development of options on futures, there will be even more opportunities for market participants to strategically offset price risk.

Questions regarding the benefits, risks and prudence involved in participating in the futures or option markets are being informally reviewed by some regulatory bodies in North America. State regulators in the US have begun to recognize that the question of LDCs' participation in futures markets is more than academic. Some LDCs have already begun trading in natural gas futures and it is our understanding that the State of New York is about to approve limited LDCs' participation in futures trading. Though futures trading in gas may now play no part in the regulatory process, it should be considered as a tool that can be used to obtain the lowest reasonable cost for natural gas for the consumer. This argument applies equally to Canadian LDCs for whom purchases from US suppliers have become a viable alternative. With this in mind, Canadian regulators should seriously consider encouraging the use of hedging using energy derivatives as an alternative to the current

practice which allows LDCs to shift the entire price risk to ratepayers. Both regulators and gas distributors could in the future face tough questions if they fail to protect customers against unusual fluctuations in spot markets through insightful hedging.

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Appendix: Accounting Treatment of Futures Trading

A future contract has the following characteristics: (a) the purchaser agrees to accept and the seller agrees to deliver a standardized quantity of a commodity or financial instrument at a specified time or for settlement in cash; (b) the contract can effectively be cancelled before settlement date by entering into an offsetting contract; and (c) all changes in value of open contracts are settled on a regular basis, usually daily. (Futures contracts in this section do not include contracts for foreign currencies.)

There are no specific accounting standards in Canada which address commodities futures contracts. However, the US practice is considered acceptable. The US position is governed by Financial Accounting Standards Board Statement No. 80 which covers the accounting for all futures contracts entered to after December 31, 1984. The main points of the statement are as follows:

- Disclosure requirements include the method of accounting for futures contracts and the nature of any item being hedged.
- Changes in the market value of a futures

contract should be recognized in income as they occur, unless the contract meets specified criteria to qualify as a hedge.

- If the transaction qualifies as a hedge, market value changes and the initial margin deposit are to be applied to the carrying amount of the asset or liability being hedged. Clearly capital gains/loss treatment would frequently be applicable in these cases.

In addition, a transaction will be defined as an hedge (is this a bona fide hedge?) if it meets the following criteria:

- The balance sheet item being hedged should expose the company to price risk or interest rate risk.
- The contract should reduce this risk and the whole transaction should be designated as a hedge. The probability must also exist that, if the market value of the futures contract changes, a corresponding change would occur in the fair value of the asset or transaction being hedged.
- Risk, as defined by the FASB, refers to the potential gain or loss that can result from changes in the market price or yield of the hedged item that eventually will be reflected in the financial statements.