Volume 3, Section 1 – McShane, Cost of Capital

Q. At page 2 of Appendix "G" to the pre-filed evidence of Kathleen McShane she provides a listing of her Publications, Papers and Presentations. Please provide a copy of:

a. "Utility Cost of Capital Canada v. U.S.", presented at the CAMPUT Conference, May 2003.
b. "Alternative Regulatory Incentive Mechanisms", October 1992

A. Attachment A - "Utility Cost of Capital, Canada vs. U.S., May 2003"
Attachment B - "Alternative Regulatory Incentive Mechanisms, October 1992."

Utility Cost of Capital
Canada vs. U.S.
May 2003

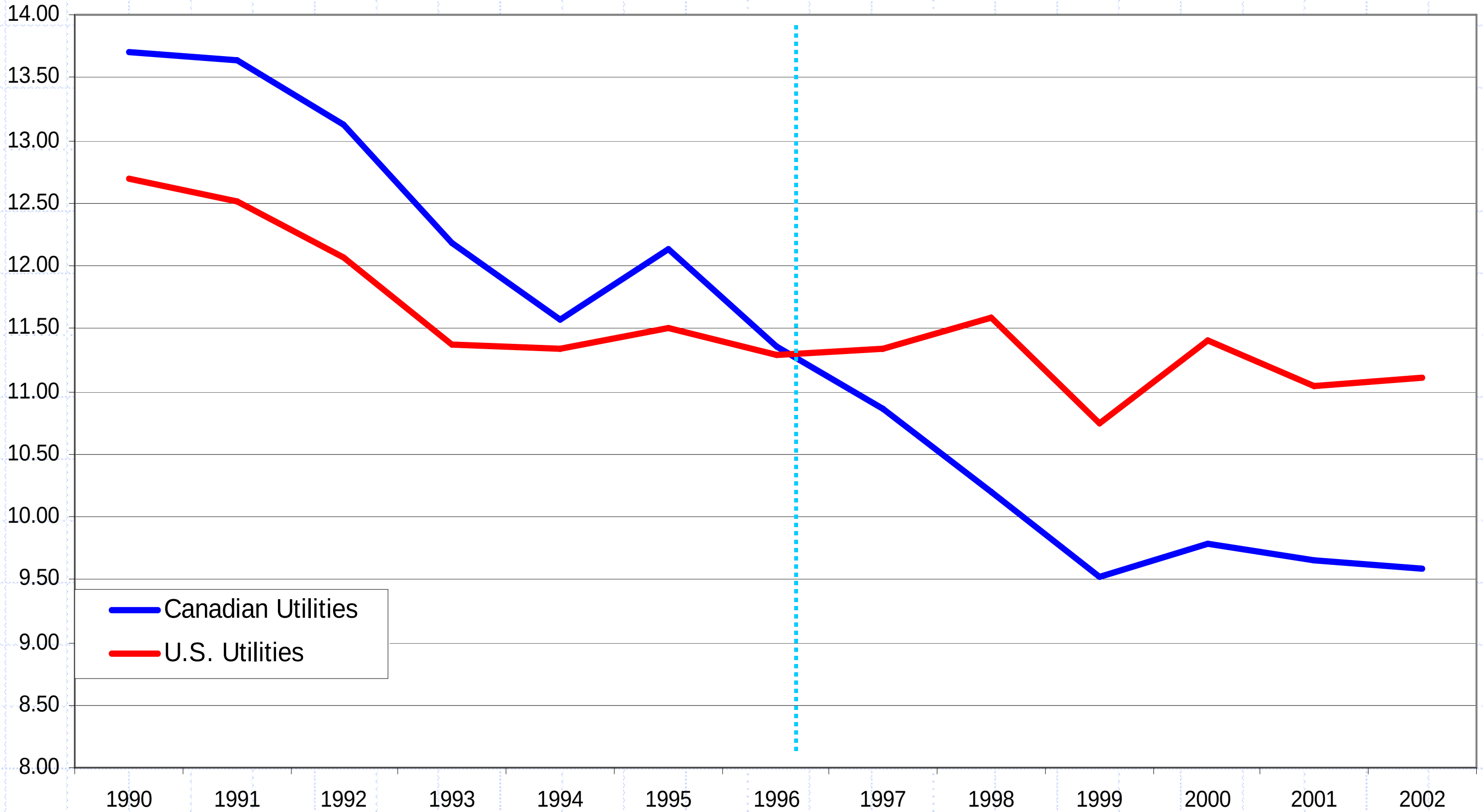
CAMPUT

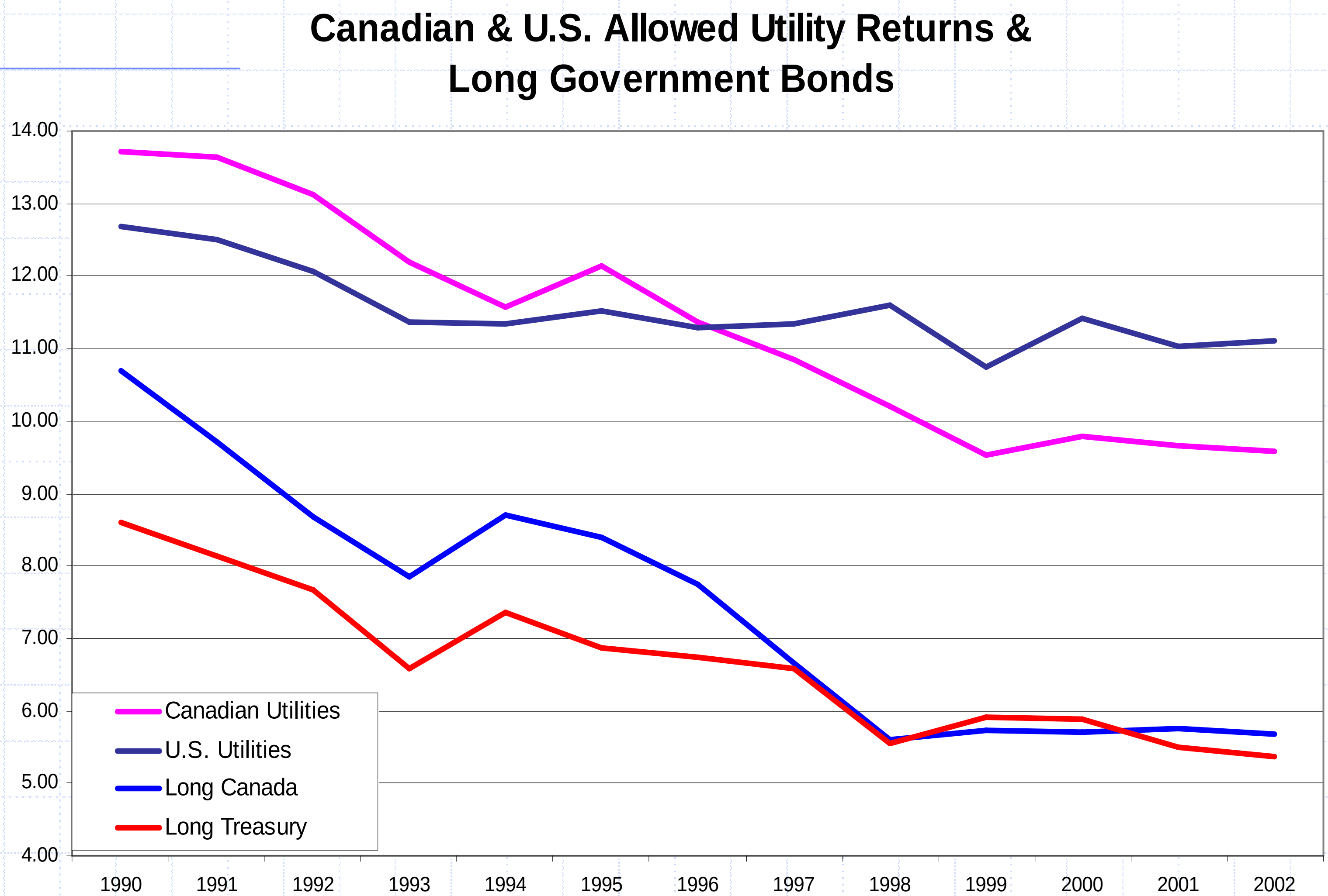
UTILITY COST OF CAPITAL CANADA vs. U.S.

KATHY McSHANE
FOSTER ASSOCIATES

MAY 7, 2003

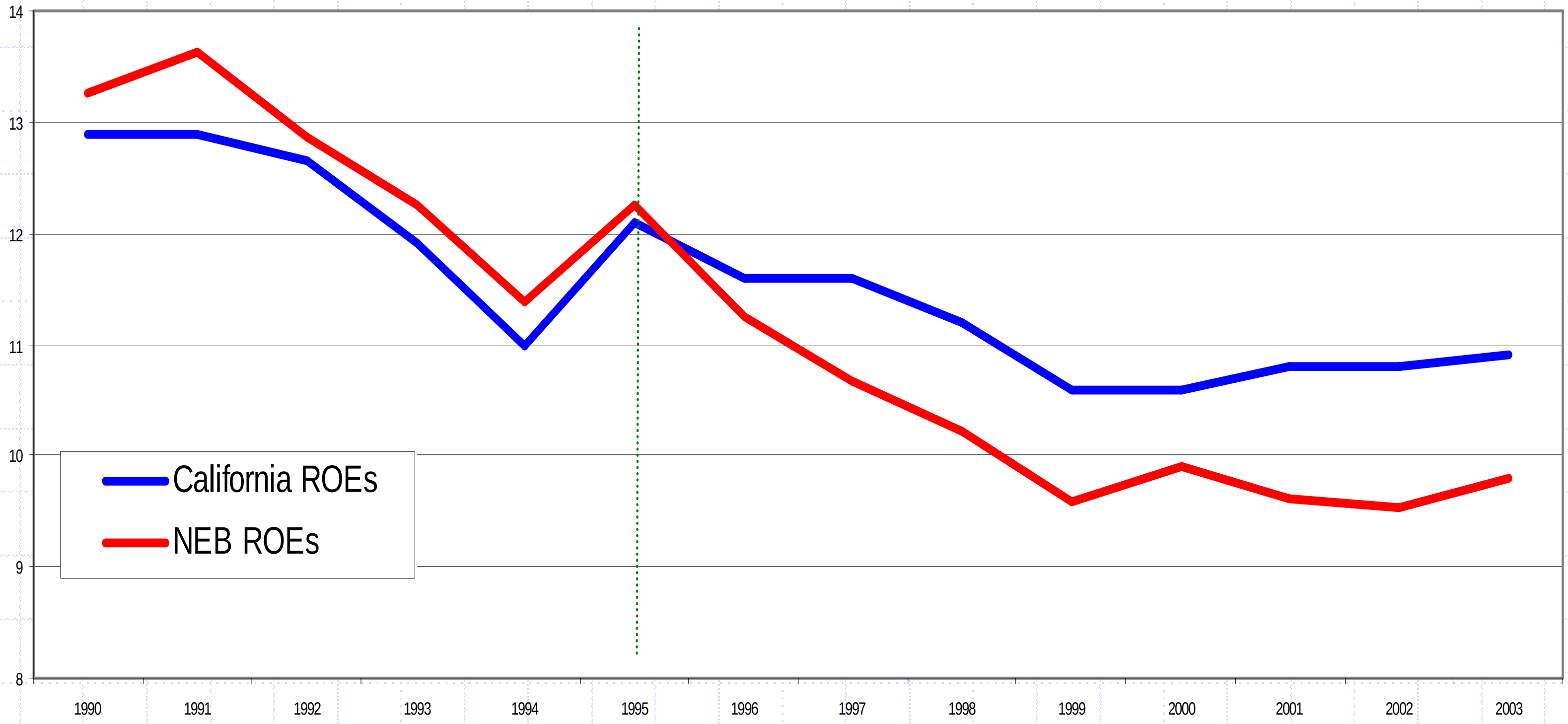
Comparison Between Allowed ROEs for Canadian & U.S. Utilities





Canadian & U.S. Allowed Utility Returns &
Long Government Bonds
14.00
13.00
12.00
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
Canadian Utilities
U.S. Utilities
Long Canada
Long Treasury

Comparison of NEB ROEs to California ROEs



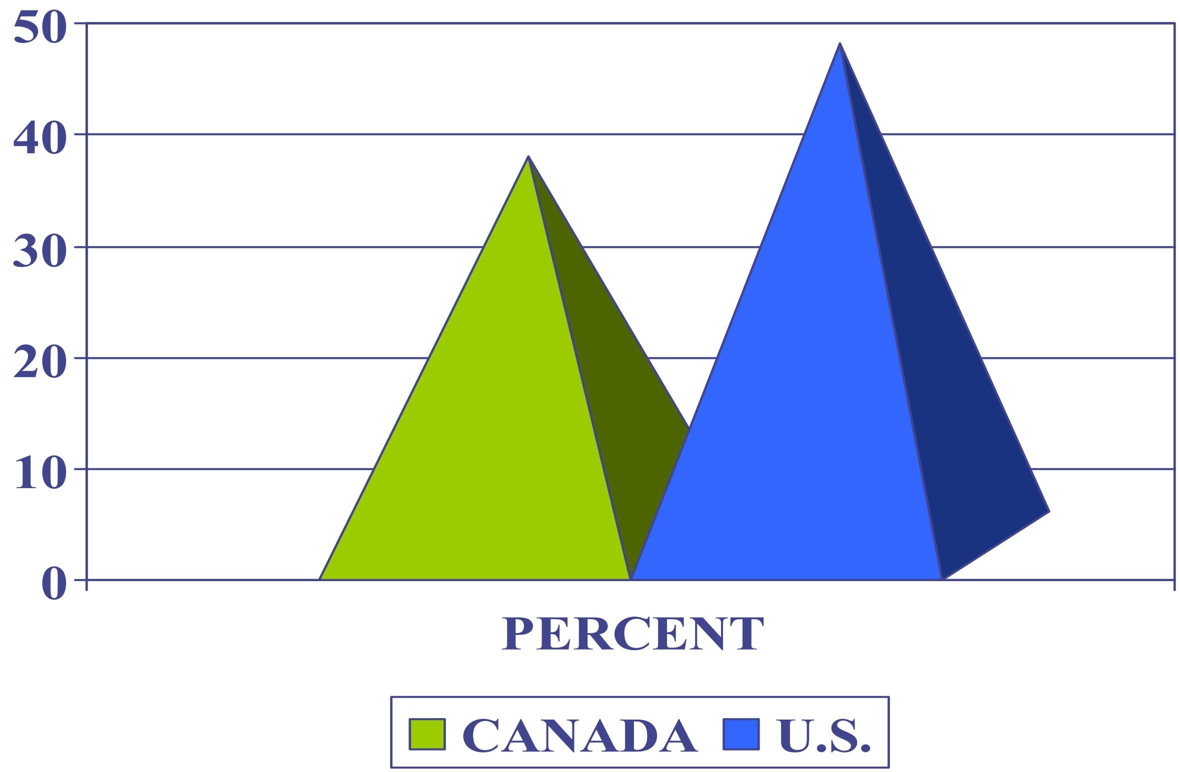
POSSIBLE REASONS FOR DIFFERENCES:

- Risk
- Financial Markets
- Taxes
- Regulatory Methodology

RISK

- Business Risk
- Regulatory Risk
- Financial Risk
  - Capital Structures
  - Debt Ratings

ALLOWED EQUITY RATIOS



FINANCIAL MARKETS

- INTEREST RATES / INFLATION
- COUNTRY RISK
- MARKET SEGMENTATION
- TAXES

TAXES

- Taxability of Shareholders
  - Institutions
  - Individuals
- Tax Differences
  - Dividend Tax Credit
  - Capital Gains Tax

METHODOLOGY

CAPITAL ASSET PRICING MODEL

ROE = Risk-Free Rate + Beta(Market Risk Premium)

Vs.

DISCOUNTED CASH FLOW

ROE = D/P + g

IMPLICATION OF ROE METHODOLOGIES

CAPM/AUTOMATIC ROE ADJUSTMENT

Δ in ROE = 75-80% Δ in Long Canadas

= Interest Rate Sensitivity of ROE

DISCOUNTED CASH FLOW

Δ in ROE = 25-35% Δ in Long Treasuries

= Greater Stability of ROE

Alternative Regulatory Incentive Mechanisms October 1992

ALTERNATIVE REGULATORY

INCENTIVE MECHANISMS

Prepared

for

Alberta Natural Gas Company Ltd.
Foothills Pipe Lines Ltd.
Interprovincial Pipe Lines Ltd.
NOVA Corporation of Alberta
Trans Mountain Pipe Line Company
TransCanada PipeLines Limited
Westcoast Energy, Inc.

by

Kathleen C. McShane

and

Stephen F. Sherwin

Foster Associates, Inc.
Washington, D.C. 20005

October 1992

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This study was prompted by the National Energy Board's call for a seminar on Incentive Regulation.

I. Rationale for Shift to Incentive Regulation

Incentive regulation has become a "catch all" term for alternatives, as well as "add-ons", to traditional cost of service/rate of return regulation, which has been criticized for a failure to be cost effective in the operation and construction of public utilities, and for providing false pricing signals leading to a misallocation of resources. This study examines a variety of proposals designed to provide utilities with incentives to render them more cost effective and reduce the regulatory burden.

The criticisms leveled at the traditional regulatory mode can be substantiated by numerous illustrations from various U.S. regulatory industries, but our analysis suggests that they do not stand the test of critical scrutiny when applied to Canadian gas pipelines. In view of that conclusion, and while we agree with the objectives of the proponents of incentive regulation, we do not find a general shift to incentive regulation as warranted. Nevertheless, we identify five mechanisms that warrant consideration for potential improvement of the current regulatory mode.

II. Criteria for Evaluation of Regulatory Schemes

We specify eight criteria and suggest that the same criteria should apply to the current as well as alternative modes of regulation:

1. Promote operational efficiency.
2. Provide incentives for technological innovation.
3. Ensure safety and reliability of service.
4. Achieve allocation efficiency through the pricing structure.
5. Provide an opportunity to earn a fair return.
6. Provide predictability and consistency to both ratepayers and investors.
7. Be consistent with public policy objectives and fair to all classes of customers and investors.
8. Minimize the cost of regulation.

III. Evaluation of the NEB's Current Regulatory Framework

Our evaluation is in terms of the above criteria and in relation to the operating and market characteristics faced by Canadian gas pipelines.

Our analysis suggests that the Board's mode of regulation, characterized by consistency and mechanisms to avoid unnecessary exposure to risk, has permitted Canadian gas pipelines to operate efficiently, avoid excessive plant investments, achieve a high degree of capital cost efficiency, yet serve as an effective instrument of national energy policy. In addition, intra-modal competition, as well as inter-fuel competition provide incentives for Canadian pipelines to operate efficiently.

Canadian gas pipelines are operating at a composite utilization rate above 90% compared to 68% for U.S. pipelines; the financing of about $13 billion of plant has been accomplished with common equity ratios of 25-35% and essentially on "flow through" income taxes, compared to about 59% common equity for the 25 largest U.S. pipelines, and normalized income taxes. The debt ratings of Canadian pipelines are in the range of A- to BBB, compared to the U.S. pipelines' current average debt rating of BBB-, brought about in part by regulatory policies deliberately exposing pipelines to asymmetrical risk.

The principal limitations of the present Canadian regulatory mode arise from the absence of pricing flexibility, a possible lack of adequate incentives for reduction of operating costs due to the requirement to pass on virtually all economies to customers, and a regulatory process that could benefit from some streamlining, but which remains significantly more efficient than at the FERC.

IV. <u>Alternative Incentive Regulatory Mechanisms</u>

Our evaluation focuses principally on their applicability to costs over which management has some control, and on the impact on the cost of attracting capital, which remains the single most important cost component, accounting for about 37% of the pipelines' revenue requirement. We view several of these mechanisms in the nature of potential "add-ons" to the present regulatory mode, and only price-cap regulation as a potential substitute, but which we do not view as currently appropriate for Canadian gas pipelines.

1. **<u>Automatic Rate Adjustment</u>**: This mechanism has been principally applied (1) to cost components over which the utility has little control, to improve its ability to achieve the allowed return in an inflationary environment and, (2) to adjustments of the rate of return by a formula. In our view, only the latter is relevant in the Canadian context. It may be possible to devise, and agree upon, a formula that would provide for automatic indexing of the equity return (within a range of long Canada rates), and which reduces the regulatory burden.

2. **Partial Cost Efficiency Mechanisms**: These mechanisms build on the concept of indexing by introducing an incentive component to encourage cost efficiency. They have been widely used in the U.S. to encourage optimal capacity factors and minimum fuel costs for electric generating plants, or to minimize purchase gas costs, or to promote conservation. For Canadian gas pipelines, only O&M costs and construction expenditures are potential candidates. In our view, without quantifiable service standards, incentive mechanisms for O&M may be counterproductive; the Canadian construction experience, where significant overruns or imprudent expenditures have been the exception, does not warrant the creation of an unavoidably complex incentive mechanism.

3. **Incentive Rate of Return**: This mechanism generally allows an incremental return as a reward for achieving either a specific performance target or better overall performance in comparison with other utilities. Canadian pipelines are too heterogenous to permit inter-company performance measurements. Specific performance targets were established for Foothills' IROR scheme, which we view as appropriate, or necessary, only for major projects, characterized by exceptional risk. An incentive return scheme applied to capacity utilization would be warranted only for projects which entail significantly greater risk of underutilization, and would need to be accompanied by a rise in the common equity ratio and/or the allowed return.

4. **Zone of Reasonableness/Profit Sharing**: The first is a frequently used mechanism to permit an adjustment of utility rates within a specified return range typically used by the CRTC, and many U.S. regulators. A profit sharing mechanism is an adjunct to permitting sharing of profits (or losses) beyond the zone between shareholders and customers, or in conjunction with performance indicators, currently used predominantly for U.S. telephone companies and for one gas distributor. In our view, the "zone of reasonableness" mechanism could be used as an incentive to reduce the frequency of regulatory proceedings; we regard, the profit sharing adjunct as unnecessary, in light of the profit limitations imposed by fixed toll regulation and potentially having an adverse impact on safety and reliability.

5. **Banded Rates**: This mechanism targets the goal of allocative efficiency by establishing upper and lower limits for tolls, and has been widely used in the U.S. for gas distributors, for both firm and interruptible transportation rates. If there is a queue for service, the fixed toll design provides the most efficient approach to allocation of firm capacity, with no need for a lower or upper band for firm transportation service. However, for pipelines that operate at less than 100% utilization, banded rates, in conjunction with the ability to retain a share of the revenues would provide an incentive to move interruptible volumes.

6. **Yardstick and Marketbasket Regulation**: The first is a form of regulation which seeks to establish utility prices based on average costs of other utilities, clearly not feasible for Canadian pipelines; the second is an attempt to judge the reasonableness of a utility's profit rate by reference to either experienced book returns of other utilities or relative stock market performance. The latter suffers from circularity and, when applied to stock market performance, contravenes many criteria for the establishment of reasonable rates.

7. **Price or Rate Cap Regulation**: Prices are allowed to rise by the inflation rate less a predetermined productivity (efficiency) gain; the methodology can contain a ceiling revenue constraint or a profit constraint. It has been applied primarily to telephone companies in the U.S. and Great Britain; and to British Gas for its "core" market.

   In theory, price cap regulation should produce technical and dynamic efficiencies; in practice it is likely to significantly raise the cost of capital for Canadian pipelines. We regard it as a currently unnecessary alternative in view of (1) the high utilization rates of Canadian pipelines; (2) an opportunity for windfall profits for some and inadequate returns for others, depending on rate base growth; and (3) a high probability of causing greater regulatory controversy.

V. Recommendations

1. Any changes to the present mode of regulation should be made gradually, based on the cost and market characteristics of each pipeline, and with due regard that any incentive scheme is likely to raise the cost of capital.

2. As a step toward streamlining the regulatory process, the Board should pursue the concept of a generic rate of return hearing resulting in a benchmark return on equity, and a formula for periodic return adjustments tied principally to changes in long Canada yields.

3. To provide an incentive to cut costs, the equity return should be set in terms of a "zone of reasonableness", but applicable only to pipelines with no major capacity expansion.

4. Although we regard an incentive mechanism for operating and maintenance expenses as unwarranted, if a cost efficiency mechanism is viewed as necessary, a sharing mechanism could be implemented under which the pipeline should be allowed to capitalize its share and amortize the savings over several years.

5. To improve allocative efficiency, pipelines should be allowed "banded rates" for interruptible volumes, with some sharing of revenues from increased throughput.

6. Since virtually all Canadian gas pipelines are operating at high utilization factors, it would be counterproductive to expose shareholders to the risk of underutilization of existing capacity, a risk which is not presently compensated in the return, except for the constraints of competition. If pipelines were to be put at risk for underutilization of new capacity any incentive scheme would require an increase in the "baseline" return, and would be contrary to the present accepted integrated system philosophy.

I. <u>THE RATIONALE FOR A SHIFT TO INCENTIVE REGULATION</u>

In recent years, interest in alternative forms of regulation has intensified across North America, arising primarily from increasing public policy initiatives to promote competition in various markets traditionally served by regulated utilities. The transition to competition in the gas supply market has intensified the ongoing controversy over the effectiveness of the traditional rate base/rate of return model in fulfilling its role of simulating transportation tolls under competition. The call for "incentive regulation" (which has become a "catch all" term for alternatives to traditional rate of return regulation, as well as "add ons" to the traditional regulatory paradigm), reflects in large part a key disenchantment on the part of various parties: a belief that traditional cost of service (rate base/rate of return) regulation does not impel utilities to achieve a degree of efficiency experienced in competitive industries.

Essentially, there have been six critiques levelled against traditional rate of return regulation:[1]

1. The inclusion in the revenue requirement of all prudently incurred costs provides no incentive for utilities to efficiently operate utility plant or to develop innovative responses to the challenges of competition;
2. Regulation condones excessive and "gold plated" plant construction for the purpose of building rate base to earn secure returns;
3. Diversification of utilities into non-regulated activities leads to shifting of costs from unregulated to regulated operations, resulting in cross-subsidization;
4. The pricing structure under cost of service regulation provides false signals which leads to a misallocation of resources;

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[1]The critiques of rate of return regulation are not new. As early as 1927, the lack of explicit incentives provided by cost of service regulation was noted by Professor Martin G. Glaeser in his text, <u>Outlines of Public Utility Economics</u> (pp. 432-433).

5. The risks associated with cost of service regulation are asymmetric; investors bear the risks of poor management decisions, but are not allowed to achieve returns above the cost of capital for outstanding performance; and,
6. The regulatory costs incurred for scrutiny of utility activities are too high.

These are serious charges, most of which could be substantiated by numerous illustrations from various U.S. regulated industries, but we do not believe that they stand the test of critical scrutiny when applied to Canadian gas pipelines.

The proposed remedies cover a variety of proposals whose goal is to explicitly provide utilities with incentives designed to render them more cost effective and innovative in an increasingly competitive society, while requiring less regulatory scrutiny.

We concur with these objectives in principle, but that does not necessarily warrant a shift to incentive regulation. Any shift must be supported by a high probability that an alternative regulatory mode will produce net benefits.

To evaluate whether an alternative mode, applied to Canadian gas pipelines, may yield net benefits, we start with the proposition that the same criteria should apply to alternative forms of regulation as to the current methodology. These criteria reflect the main objectives of any regulatory scheme: to simulate competition, and achieve operational efficiency, fairness and equity among ratepayers and investors.

II. CRITERIA FOR EVALUATION OF REGULATORY SCHEMES

1. Promote Operational Efficiency

Under competition, market forces provide a firm with the incentive to minimize costs of production, so that the firm will be able to earn a competitive rate of profit. To enhance competitive forces that provide constraints on natural monopolies, the regulatory framework for utilities should include measures to encourage (1) the most efficient combination of capital and labor inputs; (2) the lowest cost inputs (including labor, administrative and capital costs) consistent with the optimal degree of safety, and reliability of service; (3) a level of capacity compatible with efficient utilization rates; and, (4) economic financing compatible with the maintenance of creditworthiness and financial integrity.

2. Provide Incentives for Technological Innovation

For unregulated firms, technological innovation serves two purposes: (1) reduction in the costs of production and (2) creation of new products and services. The benefits from technological innovation are shared between consumers and shareholders; the former benefit from lower prices and greater choice of services; the latter benefit from potentially higher profitability. Regulation should provide the incentives for technological progress created for competitive firms by market forces.

3. Ensure Safety and Reliability of Service

Regulation should seek to ensure that pipelines maintain an appropriate level of safety and reliability of service. Safety is essential; the standards for reliability of the service are partly dependent on the terrain traversed by the pipeline, weather conditions, and the degree to which the ultimate customers have access to alternative gas supplies. In the U.S. the typical large gas distributor has access to three pipelines; in Canada, the typical distribution utility receives over 90% of its supplies from a single pipeline.

4. Achieve Allocative Efficiency through the Pricing Structure

Allocative efficiency is achieved when the rate structure allocates available capacity to those customers who place the most value on it. For an unregulated natural monopoly, this would lead to limited capacity and prices which result in monopoly profits. A goal of regulation is a rate structure which avoids giving false pricing signals that may lead to misallocation of resources.

5. Provide an Opportunity to Earn a Fair Return

Since the cost of capital is the single most important cost component of the cost of service (approximately 35-40% for the four largest Canadian pipelines versus 18% for U.S. pipelines), it is of critical importance that the regulatory mode should provide an opportunity to achieve a return commensurate with all of the risks -- including regulatory risks implicit in the mode of regulation -- to which the pipelines' capital is exposed. The opportunity should be characterized by symmetry, providing an equal probability to fall short or exceed the required return and a recognition that the required return lies above the "bare-bones" cost of attracting capital, and should contain a risk premium above long-term interest rates varying inversely with interest rates.

6. Provide Predictability and Consistency to Both Ratepayers and Investors

The predictability and consistency of rates produced by the regulatory methodology is valued by both ratepayers and investors. Rate predictability is particularly important to industrial customers whose own investment and consumption decisions are dependent on the cost of utility services. The value of predictability to investors lies in the consistency of the regulatory scheme, which facilitates the attraction of capital on the most economical terms.

7. Be Consistent with Public Policy Objectives and Fair to All Classes of Customers and Investors

Public policy objectives encompass national energy security objectives, environmental concerns, resource and industrial development, and conservation. These objectives may at times be partly conflicting, e.g., resource development versus conservation and demand side management programs imposed by regulation on gas distributors.

Fairness is an elusive concept that defies precise definition. The perception of regulatory fairness is a function of consistency, symmetry, equal treatment among regulated entities, respect for implicit covenants under which capital was committed to utilities, and judicious weighing of conflicting interest between ratepayers and investors.

8. Minimize the Cost of Regulation

The implementation and monitoring of any regulatory framework involves both direct and indirect costs. The selection of a regulatory mode should compare the costs associated with its administration, including information requirements and the degree of scrutiny needed, with the benefits gained by ratepayers, and the ability to render timely decisions.

III. EVALUATION OF CURRENT NEB FRAMEWORK FOR REGULATION OF GAS PIPELINES

No major change from the current system should be entered into lightly. Therefore, it is important to take a hard look at the National Energy Board's approach to regulation and respond to the questions of how well the present method has met the criteria for regulation and ultimately, of how well the public interest has been served by the combined efforts of the industry and regulators.

We begin our evaluation of the regulatory mode by highlighting key elements which characterize regulation of major (Group 1) natural gas pipelines:

(1) Reliance on original cost rate base/rate of return regulation;

(2) Use of a forward test year to establish the rate base, return, and operating and maintenance costs to be included in the revenue requirement;

(3) Approval of capital expansions through a facilities application process, which entails a feasibility test;

(4) Prudency reviews of actual capital expenditures in a tolls proceeding;

(5) Scrutiny of cost forecasts, allocation of costs between regulated and unregulated activities (including financing costs, e.g., capital structure) and allocation of costs among services.

(6) Reliance on deferral accounts for expenditures beyond the control of management;

(7) Design of rates on a rolled-in basis, i.e., the cost of new facilities is "rolled-in" with that of existing facilities; and,

(8) Use of a fixed toll (full fixed-variable) or variable cost of service rate design. Under the fixed toll method, a two-part rate is charged for firm transportation service: a demand charge based on peak capacity requirements, which includes 100% of the fixed charges, and a commodity charge based on annual throughput, which includes variable costs. Under the variable cost of service method, tolls vary monthly, based on actual expenses and volume throughputs.

We now evaluate the current regulatory mode by reference to each of the criteria set forth above.

1. **<u>How well does the current methodology promote operational efficiency</u>?**

The rate base/rate of return methodology, which gives the utility the opportunity to recover all reasonably incurred costs, plus a normal rate of profit, from ratepayers, has been alleged to give the utility no incentive to achieve technical, dynamic or capital cost efficiency.

- <u>Technical Inefficiency</u>

  Technical inefficiency refers to the possibility that cost of service regulation may encourage excessive building of facilities and erring on the side of too much safety, resulting in "gold plating" of facilities. The Canadian experience does not bear out either of these propositions.

  Whether there has been uneconomic construction of Canadian pipelines may be evaluated in terms of their utilization factors. The penetration of new markets is typically characterized by low utilization of facilities. If pipelines are initially operated at high utilization rates, then they are suspected of having constructed less than optimally sized facilities.

  Both TransCanada's and Westcoast's original systems were constructed before the creation of the National Energy Board. Neither of them operated at high utilization factors in their initial years. Westcoast experienced a surge in its utilization factor in the early 1970's, followed by a decline in the early 1980's, caused by Government mandated price increases adversely impacting on its Pacific Northwest export market. It undertook major facilities construction in the last five years, which were accompanied by a rise in its overall utilization factor from about 50% to a 1991 level of approximately 75%, and probably reaching 80% in 1992. This is a high level considering the absence of storage capacity.

TransCanada's and Nova's systems, during the last five years, have been characterized by capacity shortages, resulting in utilization rates of above 90% and high rates of growth in their respective rate bases. Foothills initially operated at low capacity utilization, at about an 80% level since 1988, but is now expanding its capacity to meet expected demands. ANG has operated consistently at relatively high capacity rates, and at close to 100% in recent years. Trans Quebec and Maritimes was constructed in response to a national energy policy objective to extend a pipeline into the Maritimes. That objective fell short of being attained, resulting in construction of a pipeline whose throughput capacity could be significantly increased by the installation of additional compressors.

Thus, with the possible exception of TQM, Canadian gas pipelines are operating at high utilization factors, so that there does not appear to have been an uneconomic use of capital. It is of interest to note that the 1990 utilization factor of U.S. pipelines (excluding the southwest region) was estimated at approximately 68%.[1]

Turning to potential "gold plating", every major construction project is subjected to regulatory scrutiny with respect to design criteria, and the inclusion of capital expenditures in rate base is subject to review for prudency. Moreover, Canadian pipelines are designed in accordance with CSA code requirements and in compliance with on-shore pipeline regulations. There have been a few instances -- notably in the construction of Interprovincial Pipelines's Montreal Extension -- where the prudency of expenditures was challenged. Since Canadian pipelines are now serving markets that already are, or will be, characterized by both effective product and intra-modal competition (particularly in the U.S.), it is unlikely that management would be interested in "gold plating", since it would adversely impact on growth and increase the risk of capital recovery to which all pipeline investments will be exposed in an era of increasing competition. Moreover, since the preponderance of Canadian gas customers rely on a single pipeline, subject to extreme weather conditions and/or

[1]Based on a weighted average of regional capacity utilization rates from Energy Information Administration, Capacity and Service on the Interstate Natural Gas Pipeline System 1990, p. xi.

rough terrain, an ounce of prevention, which some might view as "gold plating", may be worth pounds of curing an accident.

♦ Dynamic Inefficiency

Dynamic inefficiency refers to the allegation that under cost of service regulation management may have little incentive to improve operational efficiencies, because the benefits are passed on to customers rather than to shareholders.

Conceptually, that criticism has some merit. However, in terms of the impact on tolls of Canadian gas pipelines, it is of relatively little significance, and remedial measures may entail the more serious risk of endangering safety and reliability of service. Moreover, there remains some incentive to reduce expenditures to improve the achieved return during the test year, despite the fact that these cost savings are typically passed on to customers in the subsequent toll proceeding in the form of lower rates. In the longer run, greater competitive pressures render it in the self interest of pipelines to operate efficiently.

In contrast to the experience of the largest 25 U.S. pipelines,[1] where operating and maintenance costs typically account for about 45-50% of the revenue requirement, for Canadian pipelines the proportion of operating and maintenance costs averages about 12%.[2] A substantial portion of this level, certainly more than 70%, is irreducible because these costs are required to maintain minimal reliability and safety

[1]Accounting for about 90% of all Class A U.S. pipeline utility plant investments.

[2]The respective ratios should be viewed as order of magnitude comparisons. The U.S. data include all operating costs (covering gathering, storage and transmission, and minor amounts of production and distribution) but exclude purchase gas costs, transmission by others and compressor fuel. The 12% approximation for Canadian O&M also excludes transmission by others and compressor fuel. The individual company ratios range from below 10% for TQM to about 12% for Foothills and TCPL, to 24% for Nova, and 37% for Westcoast. The latter two are relatively higher because Nova transports processed gas from a large number of geographically diverse receipt points, and 70% of Westcoast's O&M relates to raw gas transmission and processing. In contrast to the other pipelines, Westcoast's operation of processing plants is unique in terms of both magnitude of costs in relation to total costs, as well as operational risks.

standards. Hence, increased operational efficiency is unlikely to have a significant impact on rates.

♦ <u>Capital Cost Efficiency</u>

The single most important cost efficiency achieved under the current regulatory mode has been the ability of Canadian gas pipelines to finance their plant investments at economic rates, and at a significantly lower cost of capital than their U.S. counterparts. That proposition becomes self-evident by a comparison of capital structures and debt ratings.

Canadian pipelines have financed their rate base investments with common equity ratios in the range of 25-35%, and debt ratios ranging from 60-75%. By comparison, the largest 25 U.S. pipelines' common equity ratios (1987-1991) have averaged about 59%, debt ratios, 40% and preferred stock about 1%. Whereas all Canadian gas pipelines (except Foothills) are now on "flow-through" taxes, all U.S. pipelines are on "tax normalization" (deferred taxes), with a composite tax rate (for revenue requirement purposes) of about 36-38%, and a reported effective tax rate of about 31%.

The debt ratings of Canadian gas pipelines are in the range of A- to BBB; the debt ratings of the U.S. pipelines have been downgraded in the last decade to where they are now only BBB-. These low debt ratings were attributed by Standard & Poor's to relatively poor return levels caused by unregulated operations, widespread discounting of transportation rates, losses from take-or-pay gas contracts, and extended periods of warm weather which impact negatively on earnings under the modified fixed-variable methodology which has been used for rate making.

The specific elements of the NEB's regulatory mode which account for the greater capital cost efficiency of Canadian gas pipelines are: the reliance on a fixed toll (with deferral accounts) or a variable cost of service rate design methodology, the forward test year and a reasonably consistent regulatory framework. By contrast, the U.S. regulatory mode has been characterized by change bordering on turmoil, and deliberate exposure of the pipelines to asymmetrical risks, resulting in a significantly higher cost of capital than for Canadian pipelines.

2. <u>Does the current regulatory method promote technological innovation</u>?

Technological innovation -- an aspect of dynamic efficiency -- is not specifically encouraged by the current regulatory mode, since all benefits from cost reducing measures or development of new services area passed on to consumers. However, since the gas pipeline industry is not subject to the same potential for technological advances as, for example, the telecommunications industry, the relative lack of incentive may not be as critical. Nevertheless, since natural gas competes with other forms of energy, competition for markets provides some incentive to pursue cost reducing measures and fashion services to meet the specific needs of customers.

On the other hand, the regulatory process itself tends to dampen the incentive for technological innovation. Not infrequently, intervenors seize on managerial efforts for greater operational efficiencies, expansion of markets, or technological innovations as evidence that the utility's risk has declined, which then becomes translated into lower allowable returns. Thus, stockholders tend to be penalized for achieving dynamic efficiency. While the extent, if any, to which such "lower risk" arguments may have influenced the Board's return awards cannot be ascertained, it is, nevertheless, a matter that deserves regulatory attention, in terms of providing appropriate managerial incentives.

3. <u>Does the current methodology ensure safety and reliability of service</u>?

The regulatory compact which underlies rate of return regulation holds that, in return for an exclusive franchise, coupled with the opportunity to recover all prudently incurred costs and earn a fair return on equity, the utility has the obligation to ensure safety and provide a high degree of service reliability, at reasonable rates. The relatively high degree of assurance of cost recovery implicit in the current form of regulation encourages management to fulfill customer expectations in the areas of safety and reliability, since there are no incentives to cut costs to a level which would endanger the reliability of service, partly because cost reductions redound to the benefit of ratepayers and a failure to provide safe and reliable service may adversely impact on regulatory return awards.

4. <u>Do the rates set result in a reasonable degree of allocative efficiency</u>?

The current mode of regulation is designed to ensure that (1) rates are cost based; (2) ratepayers pay similar rates for similar services; (3) that costs are appropriately functionalized to assure that ratepayers are incurring the costs attributable only to the services they request; (4) costs are scrutinized to avoid cross-subsidization; and (5) the rates are designed (i.e., fixed tolls) so as to encourage efficient utilization by customers.

While all of these facets of pricing are intended to promote allocative efficiency, it is nevertheless true that, in competitive markets, rates would be based on expected (replacement or marginal) costs, instead of on average historic costs which reflect front end loading. Reliance on historic average costs may send incorrect signals to the users of utility services, which may then cause a misallocation of resources. In addition, cost of service regulation entails price rigidity, or the inability to vary rates to meet competitive conditions, which would tend to accentuate allocative inefficiency.

These criticisms have considerable conceptual merit. However, recognizing that past allocative inefficiencies cannot be remedied, the real issue is whether the current level and structure of rates, given the specific circumstances of Canadian pipelines, do indeed provide false pricing signals, and whether the current competitive environment warrants giving management greater pricing flexibility.

The degree to which rates based on original cost cause allocative inefficiency is dependent on the rate of inflation and the rate of growth of the rate base. High rates of inflation accentuate allocative inefficiency; rapid expansion of facilities, if costs are "rolled-in" with existing facilities, tends to mitigate the false market pricing signals of original cost regulation.

The recent rapid expansion of the three largest Canadian pipelines, Nova, TransCanada and Westcoast -- accounting for about 88% of 1991 plant net investments[1] -- has significantly mitigated potential false pricing signals. The combined net plant of the six major gas pipelines now total about $9.9 billion, of which about 40% reflect post-1985 dollars;[2] by year-end 1993 that ratio should approach 50%.

Allocative efficiency cannot be determined solely by reference to rate base vintages, but must also consider competitive forces, particularly the degree to which U.S. pipeline rates are impacted by original cost regulation. At the end of 1991, the six largest Canadian pipelines showed net plant about 26% depreciated; the net plant of the largest 25 U.S. pipelines was approximately 58% depreciated.[3] These comparisons suggest that there is significantly greater allocative inefficiency in the rates of U.S. pipelines compared to Canadian pipelines, and that from a competitive viewpoint, the original cost rolled-in ratemaking methodology has created no allocative inefficiency in terms of relative rate levels.

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[1]The year-end 1991 net plant investments were about $9.9 billion: TransCanada $4.7; Nova $2.8; Westcoast $1.2; Foothills $0.78; TQM $0.36; and, ANG $0.036.

[2]Gross plant investments in 1985 were $8.1 billion compared to an estimated $13.3 in 1991.

[3]The composite gross plant in 1985 of the 25 largest U.S. pipelines was $37.4 billion, and the net plant $17.0 billion; by 1991 the gross plant had risen to $44.4 billion and the net plant to $18.7 billion. This suggests that (disregarding retirements) the $7.0 billion of increased investment was financed by about $5 billion from depreciation funds (averaging about 3% of gross plant) and $2 billion of new capital and reploughed earnings.

However, in contrast to U.S. regulation, the current mode of regulation does not provide for significant pricing flexibility (except for interruptible rates) to allow adjustment to changes in competitive conditions. Moreover, cost of service pricing, where rates are inversely related to the utilization factor, may be viewed as inconsistent with what would be expected in competitive markets. Under competition, allocative efficiency would lead to higher prices when demand rises, in order to ration available capacity; lower demand would lead to lower prices to encourage higher capacity utilization. The existence of competition in U.S. markets, enhanced by the implementation of Order 636 by the FERC and the potential trend toward incentive rates, warrants an evaluation of allowing Canadian gas pipelines greater pricing flexibility.

5. Does the current methodology provide an opportunity to earn a fair return on investment?

The current method of regulation carefully assesses the business risks to which the utility shareholder is exposed, establishes a capital structure intended to be compatible with the level of business risk and with minimizing the cost of capital, allows a return on equity which the capital markets have deemed to be compensatory, and provides the pipeline with a fair opportunity to earn the allowed return through the rate design, deferral accounts and a forward test year. These last three provide a high degree of assurance of earning the allowed return; thereby lowering the cost of attracting equity capital. The combination of the rate design and use of deferral accounts virtually eliminates the potential for "windfall" profits, while effectively providing a floor to the earned return.

One drawback of the current system as regards the fair return is inherent asymmetric risk; utility shareholders are effectively penalized for "imprudent" behavior, through disallowance of costs, but do not achieve offsetting rewards for exceptional performance; e.g., if the management produces cost reductions, they are passed on in their entirety to customers.

The key assumptions underlying the fair return under the present regulatory mode are the covenant that the utility is provided an opportunity to recover its full revenue requirement, but that the utility is at risk for technological or economic obsolescence which may cause "stranded investments". However, it does not envision that the pipeline is at risk for underutilization of facilities, unless the revenue requirement bumps against the ceiling of competitive prices. The investor is also at risk that the regulatory mode may change, with the recognition that such a change from the present mode is likely to expose investors to significantly greater risk. If the regulator deems it appropriate to expose the pipeline to the risk of underutilization of capacity, it should be specified at the outset and the accompanying higher risk reflected in the fair return.

6. <u>Does the current system provide predictability and consistency</u>?

Reliance on historical costs, rolled-in rates and a fixed toll rate design all promote predictability of rates and the unlikelihood of significant rate shock. However, perhaps most important in this regard is the Board's commitment to its regulatory philosophy. It is this aspect of "predictability" which benefits both ratepayers and investors. For example, over the past decade, the Board has not deviated from the fixed toll method of regulation, despite claims of unfair treatment from U.S. pipelines. (Significantly, in light of the U.S. pipelines' transition from a merchant/transporter role to one of open access transporter, the FERC has adopted the full fixed-variable rate design.) The Board has also remained firm in its policy of rolled-in rates, despite some arguments favoring incremental rates. It has consistently set capital structures on the basis of explicit criteria regarding business risk and avoidance of cross-subsidization; in the preponderance of cases, the allowed returns have been consistent across the regulated pipelines, with an explanation of the basis for the allowed returns.

On these bases, investors have an unrecovered investment of approximately $10 billion committed to the Canadian gas pipeline industry, in the expectation that regulatory treatment would continue to provide a similar degree of assurance of recovery of capital and a fair return on capital. It has been the expectation that this mode of regulation would be preserved, and that the regulator would respect the implicit covenants under which capital is typically committed to utilities, which has allowed Canadian gas pipelines to be highly leveraged (low equity ratios) and yet to attract both debt and common equity at rates well below those of U.S. pipelines.

7. Does the current regulatory mode promote fairness and consistency with public policies?

The National Energy Board is charged with the task of balancing the interests of all parties affected by its decisions: producers, distributors, end users, investors, and the national interest. While economic theory would suggest that the achievement of "economic efficiency" would result in fairness to all parties and promote the public interest, in reality, the attainment of fairness and the public policy objectives is a compromise between often conflicting interests. For example, the construction of the TQM line, which would not have been built on the basis of a strict economic efficiency criterion, was determined to be in the public interest, in light of a national policy of energy self-sufficiency.

The very basis for the current investigation of incentive regulation is at least in part the result of a question of fairness. The Background Paper notes that critics of the cost of service have argued that falling prices and profit margins for producers should have spurred cost cutting in the pipeline sector (p. 10). This is a plea for "sharing the misery" which is not a valid standard under any form of regulation.

On the other hand, a stagnating economy may create public perceptions that could render it difficult to award utilities a fully risk compensatory return within the traditional regulatory mode.[1] Since effective regulation rests on public acceptability and perceptions of fairness, incentive schemes may provide a potential "safety valve", to satisfy the perception of fairness, in a setting in which utilities cannot be provided with fully compensatory returns.

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[1]A recent Board return decision suggests, on its face -- but not necessarily in terms of its end result -- that the intended equity risk premium above long Canada bonds may have been reduced from the typical 4 percent to 3.25 percent, in conjunction with a reference to the current state of reduced returns achieved by other companies.

8. Is the Current Regulatory Model Implemented through an Efficient Regulatory Process?

The current regulatory process is characterized by periodic information requirements, a review of capital expansion plans, and a detailed, and frequent, scrutiny of each of the major pipeline's revenue requirement.

In comparison with the FERC's reporting requirements, the NEB's requirements remain less burdensome. The scrutiny of expansion plans is more careful in Canada than in the U.S.; the frequency and depth of scrutiny of the pipelines' revenue requirement is also greater than in the U.S. However, the efficiency of the Canadian regulatory process -- in terms of timely rendition of adjudicating decisions -- far exceeds that of the FERC, where the typical elapsed time between the application for a rate increase and the final decision is 30 months.[1]

The relative efficiency of the adjudicating process should not deflect from the possibility of reducing regulatory costs. The critical scrutiny of the revenue requirement, by both regulators and intervenors, has been accompanied by a process of pre-trial interrogatories that in some areas -- but interestingly not in the most contested area of rate of return -- far exceeds reasonable clarification or discovery. The hearing process is frequently characterized by repetitious cross-examination. Moreover, the "hands on" approach to regulation by numerous parties may inhibit legitimate managerial prerogatives, which is not conducive to optimizing cost effective operations.

While recognizing that any form of regulation, designed to restrain what in its absence would result in monopoly profits, entails costs, the examination of mechanisms that allow streamlining the regulatory process is warranted.

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[1]Report to Interstate Natural Gas Association, entitled Risk of the Interstate Natural Gas Pipeline Industry, by A. L. Kolbe, W. B. Tye and S. C. Myers, p. 2-13. The length of the adjudicating process has led to widespread reliance on settlements, and increasing emphasis on "rule making", which is, however, also characterized by lengthy delays.

Conclusions

The preceding analysis suggests that (1) the Board's current mode of regulation has not produced significant operational or allocative inefficiencies and (2) the regulatory methodology, including its consistency and mechanisms to avoid unnecessary exposure to risks, has been the key element which has permitted Canadian pipelines to operate efficiently, avoid excess plant investments and achieve a high degree of capital cost efficiency, yet serve as an effective instrument of national energy policy. Nevertheless, there are areas which lend themselves to improvement particularly in the areas of allocative efficiency and regulatory streamlining.

However, in light of the relative importance of capital costs to the revenue requirement for the generally expanding Canadian pipeline industry (approximately 37% of the total revenue requirements of Canadian gas pipelines is the cost of financing, compared to 16% for the more depreciated U.S. pipelines), a key consideration in the selection of any alternative regulatory mechanism is its impact on the cost of capital.

To the extent that either (1) the variability of returns is increased by a change in the current methodology, or, (2) the symmetry of the risk exposure is shifted to shareholders, the current levels of allowed returns and/or prevailing equity ratios will not be adequate to attract capital. The potential benefits from any regulatory mode that imposes a cost minimization mechanism but exposes the pipeline to greater risk of shortfall from the required return must be weighed with the increased cost of financing pipeline operations.

IV. Alternative Regulatory Mechanisms

The incentive mechanisms which have been proposed or implemented cover a broad spectrum, from those targeting a specific cost area to the replacement of cost of service with price cap regulation. They range from attempts to lessen the regulatory burden (e.g., purchased gas adjustment clauses and generic rate of return formulae) to improving specific aspects of operational efficiency (incentive return based on utilization factor of electric generating plants) to an overall improvement in operational and allocative efficiency (price caps). Our evaluation commences with the simplest mechanisms, which are essentially "add ons" to cost of service regulation, and progresses to successively more complex techniques, covering the following:

(1) Automatic Rate Adjustments;
(2) Partial Cost Efficiency Mechanisms;
(3) Incentive Rate of Return;
(4) Zone of Reasonableness/Profit Sharing;
(5) Banded Rates;
(6) "Marketbasket"/"Yardstick" Regulation; and,
(7) Price Cap Regulation.

These mechanisms do not necessarily constitute an "either/or" proposition, e.g., mechanisms which focus on allocative or pricing efficiency may be combined with mechanisms designed to improve operational efficiency. In principle, it is desirable to custom design an incentive ratemaking methodology which best suits the circumstances of each pipeline.

While our evaluation of alternatives relies on the criteria set forth in Section II, we do not reiterate or apply each of these criteria to the first six mechanisms because they are either "add-ons" to the present methodology, or clearly have relatively little merit in the Canadian environment. However, price cap regulation is evaluated in terms of each of our eight criteria.

In our view, the adoption of any alternative should be subject to the reservations (1) that the targeted area of improvement lead to net benefits, after considering potential deteriorations in other areas, and (2) that it be compatible with the operating characteristics and market conditions faced by Canadian pipelines.

1. Automatic Rate Adjustments

Automatic rate adjustments were used in the U.S. relatively frequently during the late 1970s and early 1980s when inflation made timely regulatory relief (through a general tolls proceeding) virtually impossible. The adjustments were typically applied to a major cost component over which the utility had little control, e.g., the cost of purchased gas for gas distributors, or fuel costs for electrics. While not strictly an incentive mechanism, automatic adjustments provided the utility a higher degree of assurance of earning the allowed return and helped streamline the regulatory process.

Two states have implemented automatic rate adjustments to permit achievement of the allowed return. In 1982 Alabama began using a "Rate Stabilization and Equalization Program", intended to avoid large general rate increase requests. When the return on equity falls below a certain level, customers' bills are adjusted (quarterly) to restore the return to the allowed level.[1] In return for the equalization plan, the company agrees to make no requests for a general rate increase, or a change in the allowed return range, for a given period of time.

The most recent automatic rate adjustments which have been implemented are in the area of demand side management where profits have been decoupled from revenues, and customer bills are adjusted through volume "true ups" to offset what otherwise would be lost revenues resulting from conservation efforts.

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[1]A similar plan was adopted in New Mexico in the 1970s, but was abandoned after a few years.

A further type of indexing which has been available, but not implemented without exercise of judgement, is a formula approach to adjusting the allowed rate of return (often referred to as "generic" rate of return). Formulas based on the discounted cash flow test were developed and published by the FERC for electric utilities, and by the Ontario Telephone Commission for small independent telephone companies. To our knowledge, the allowed returns never coincided with the index value and typically exceeded the index value. However, the index provided a benchmark or point of departure to which judgement was applied.

Automatic rate adjustments may be appropriate in instances where (1) the progression of inflation otherwise would preclude the recovery of incurred costs due to an unavoidable regulatory lag; (2) the utility has no control over the cost; or (3) where public policy considerations seek managerial behavior which, without such a mechanism, would preclude the utility from earning a fair return. Reliance on automatic adjustments in these instances improves the ability to earn a fair return and streamlines the regulatory process.

Operations and maintenance costs which tend to rise with the rate of inflation are a potential candidate for indexing since these costs may also present a potential area for a cost efficiency mechanism (see Partial Cost Efficiency Mechanisms). A combined index/cost efficiency mechanism could be considered for pipelines whose rate base growth does not entail O&M growth which outpaces inflation.

Since the cost of capital is the principal component of the revenue requirement for Canadian gas pipelines, it is a prime candidate for "indexing". The growing reliance on the risk premium test by this and other regulatory Boards, as well as the weight put on its results by the various experts who appear in pipeline toll proceedings, suggests that a formula could be agreed upon which could automatically adjust the rate and limit the need for reevaluation either by specifying a band of long Canada rates (e.g., 8% - 12%) within which the index applies and/or a time limitation (e.g., every three years). Changes in individual companies' business or financial risks could still be addressed in a regular toll proceeding.

The indexing formula should (1) use as a point of departure a return which reflects the results of all methodologies to which the Board gives weight in arriving at its decision, and (2) incorporate adjustments based on changes in interest rates and the inverse relationship between interest rates and the risk premium.

Use of a formula would:

(1) Not constitute a major departure from the current regulatory mode;
(2) Continue to allow the utility the opportunity to earn a fair return;
(3) Would not increase the variability of returns, and should not increase the cost of capital, assuming that the agreed upon formula fully captures changes in the required return, and therefore would continue to allow pipelines to operate at relatively low equity ratios;
(4) Would make allowed returns more predictable from the investors' perspective; and,
(5) Would streamline the regulatory process.

2. <u>Partial Cost Efficiency Mechanisms</u>

Partial cost efficiency mechanisms are the principal method of incentive regulation which have been used to date in the U.S. These mechanisms generally are intended to reward or penalize a utility for efficient or inefficient management of a key cost category. They effectively build on the concept of indexing, by introducing an incentive component to encourage cost efficiency.

The effective use of partial cost efficiency incentive mechanisms should exhibit the following characteristics:

(1) The mechanism should focus on elements whose cost is a significant component of the revenue requirement, or be of significant public policy concern, to provide a sharing of benefits by ratepayers and shareholders.

- This type of incentive mechanism has been predominantly used in the electric utility industry and is intended to encourage electrics to operate generating units at optimal capacity factors and minimize fuel cost.

- In the gas distribution industry, reliance on sharing mechanisms has shown some recent increase in the area of minimizing purchased gas costs.

- In the area of demand side management, incentive techniques have been applied in both the electric and gas distribution industries to encourage management to promote conservation. Here, the regulator is providing a financial incentive for management to achieve a public policy goal, which is in contrast to the traditional objective of maximizing profits through maximizing sales, but which is consistent with the idea of optimal use of capital resources, when all societal costs are considered.

- Incentive mechanisms have also been applied to construction costs, particularly with respect to nuclear plants. While a number of states have established caps on construction costs, with any excess presumed to be imprudent, a few have relied on symmetrical incentive approaches to recovery, under which there is a sharing of under- and overruns.

(2) The mechanism should apply to costs over which management has control.

- The purpose of the mechanism is to encourage a behavioral response on the part of management. It makes no sense to reward/penalize management for changes in costs (e.g., taxes) over which they have no control.

- As an example, prior to deregulation, gas distributors purchased virtually 100% of system gas supply from the pipeline; the regulator typically allowed 100% of changes in gas costs to flow through automatically to customers via a Purchased Gas Adjustment Clause. With open access on pipelines and a shift of responsibility for gas contracting to distributors, the PGA clause is being rethought. Four states now provide for some sharing between customers and shareholders for decreases in purchased gas costs below a benchmark rate.

(3) The mechanism should not lead to offsetting incentives for deterioration of performance in other areas.

- For example, the use of incentives to increase an electric utility's generating unit's reliability has been recognized to potentially introduce an offsetting incentive to increase operating and maintenance costs and potentially increasing the total costs.

(4) The mechanism should be symmetric in reward and penalty.

- For example, a prudency review of distributor gas costs may be viewed in some respect as an incentive: management has the incentive to enter into prudent contractual arrangements or face potential disallowance, but unless there is an opportunity to earn a reward as a result of outstanding performance, the risk is asymmetric.

- The explicit incentive may only be expressed in potential reward terms; this does not necessarily imply asymmetry in favor of the shareholder. "Positive" incentives tend to realign the asymmetry of risk which the shareholder faces under traditional regulation.

(5) The mechanism should provide the opportunity for rewards and penalties which are of sufficient enough magnitude to influence management behavior, but not large enough to potentially cause financial distress or returns of a level which would endanger the public acceptability of the mechanism.

- As an example, in 1983 New York introduced an Incentive Fuel Adjustment Clause for electric utilities. It provided that only 80% of the first $50 million of deviation from the forecast fuel cost level would be passed through to customers, 90% of the next $50 million, and 100% of any further deviations. The total potential reward or penalty was limited to $15 million to avoid both excess profits and to protect a degree of financial integrity.

(6) The mechanisms should be subject to alteration in response to changes in industry structure or underlying market conditions.

- If a cost category now subject to management control is subjected to regulation or legislation which effectively frustrates the incentive mechanism, it would be unfair not to remove or alter the mechanism (e.g., legislation requiring expenses for complying with environmental standards could invalidate or warrant adjustment of the parameters of an incentive mechanism covering either O & M or capital expenditures).

(7) The reward/penalty structure should be of sufficient permanence so that management will not discount the ability to achieve the potential reward.

- While no Board can bind the decisions of its successors, a record of consistency and fairness in the regulatory mode will lend credence to management's belief that the rewards provided for under the incentive mechanism will in fact be allowed.

With these considerations as well as the criteria for an effective regulatory model in mind, we look at the potential areas which may lend themselves to efficiency mechanisms for Canadian gas pipelines.

Given the operating characteristics of Canadian gas pipelines, there are only two costs areas which are potential candidates for the above described efficiency mechanisms: construction expenditures and operating and maintenance costs directly under management control.

With respect to construction expenditures, the need for an efficiency mechanism, i.e., a sharing of cost over- or underruns is unwarranted in light of the experience of Canadian pipelines. It is notable that the use of construction expenditure efficiency mechanisms has been virtually limited to the electric utility industry where cost overruns and disallowances for imprudent costs of nuclear plants have run into billions of dollars. The overall experience of Canadian pipelines does not suggest that cost overruns have been a significant enough issue to justify the creation of an incentive mechanism which would potentially provide an inducement to overestimate the projected costs of construction.

We recommend against subjecting O&M expenditures to an efficiency mechanism, for the following reasons: (1) they account for too small a proportion of the revenue requirement (except for Westcoast), and contain too high a proportion of costs beyond management control to warrant putting the pipelines at significant risk for their recovery; (2) mandating efficiency gains potentially endangers the safety and reliability of the pipeline; or alternatively, focusing on O&M expenditures may instill an incentive to build unnecessary safety and reliability into the system. Without quantifiable standards and a cost effective monitoring system, incentive mechanisms which specifically target O&M is likely to be counterproductive.

On the other hand, we recognize that O&M expenditures are a contentious component of the revenue requirement, frequently subjected to line by line scrutiny. We believe that the attention paid to O&M expenses arises from the fact that this component of the revenue requirement represents the area in which access to information is most equally shared between pipeline and intervenor. However, it is unlikely that controllable O&M costs account for more than 5% of the revenue requirement (except for Westcoast), so that potential savings would not significantly impact the toll.

On balance, we do not find that the operating characteristics or the historical experience of Canadian pipelines warrants implementation of a cost efficiency sharing mechanism which targets a specific cost category. Nevertheless, if operational efficiency is viewed as an area where greater incentives need to be provided to either continue or improve the prevailing levels, then an effective technique would be one in which economies and diseconomies, from an approved base line level, would be shared with the shippers, and the pipeline can capitalize its share, earn a return and amortize the savings over a specified time, or absorb its share of diseconomies. In this event, we would recommend that the allowed increases in O&M be indexed to inflation to avoid the potential allegation of "gaming", i.e., that the pipeline would deliberately overstate expected O&M to assure the achievement of "savings". The index would need to be adjusted for the impact of "exogenous" cost factors, e.g., environmental regulations. A periodic reevaluation of the "base line" may be necessary to take account of the cost impact of aging equipment.

3. Incentive Rate of Return

An incentive rate of return mechanism allows a firm an increment above the normal allowed return as a reward for achieving a particular goal. The prospect of earning an incremental return is intended to provide incentives for management to achieve the performance targets. There is a sharing of benefits between customer and shareholder: the customer benefits from reduced cost or improved reliability of service; shareholders benefit from the ability to earn increased profits. The key feature of incentive return is that the potential return increment is tied directly to a performance target. Reliance on incentive rate of return is increasing in the area of demand side management performance and has been implemented with multiple performance targets.

An effective framework for incentive return should set forth the objective of the incentive return mechanism, specify attainable criteria or performance targets, the potential rewards and penalties for meeting the performance targets, and set the reward/penalty mechanism at a level which provides an adequate incentive to pursue the specified objectives.[1]

An incentive rate of return (IROR) mechanism for construction costs was utilized by this Board for Foothills, "to provide just and reasonable compensation for investors" and "to provide incentives to promote good cost control".[2] Under that IROR scheme, the ratio of actual capital costs to filed capital costs determined the rate of return to be earned on any cost overruns. The higher the ratio, the lower the marginal return earned on the additional dollars spent, therefore providing an incentive to keep costs down. The rates of return approved by the Board specifically acknowledged that the potential variability of returns introduced by the incentive mechanism exposed the investor to increased risk. That risk was reflected in an Incentive Rate of Return risk premium of 0.4-0.6% (depending on the pipeline zone). The benefits from the IROR to shareholders were retained by translating the incentive return into a one-time adjustment to the rate base, on which an "operating phase" rate is now earned.[3]

With respect to the Board's incentive return for construction costs, the concept was similar to the partial cost adjustment mechanism for construction costs discussed earlier. However, the specific formulation reflected public policy goals and the need to provide an opportunity to earn a fair return to attract capital for what was anticipated to be a mega-project, where the costs could have significantly exceeded the original estimate. The plan did not entail the

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[1]A structured framework for an incentive return mechanism which meets these criteria differs from the concept of a penalty return regulators have used to register displeasure with utility performance or, less frequently, an increment to reward exceptional performance. In these instances, the use of an incentive return has been judgemental, erratic, and not subject to any pre-specified standards.

[2]<u>Reasons for Decision</u>, November 1979, p. 3-3.

[3]Under this scheme the present value of the revenues to the shareholders provided by application of the Operation Phase Rate to the adjusted rate base equals the present value of the revenues to the shareholders provided by application of the Incentive Rate of Return to the actual rate base.

possibility of non- recovery of capital as have the incentive mechanisms applied to nuclear plants, where construction cost sharing mechanisms have been put in place after construction was begun and the probability of overrun far exceeded possible underruns.[1] We are of the view that the IROR incentive return mechanism may be warranted in special circumstances where the size and risks of the project render attraction of capital otherwise uncertain, but public policy considerations support undertaking the project.

The most recent wave of incentive return mechanisms are attributable to growth in demand side management, with its promotion of public policy goals. Boston Gas, for example, is allowed to earn an additional equity premium of 0.5% linked to the company's ability to demonstrate through a performance metering study that it had achieved its estimate of savings over a specific period of time.

A few incentive return programs have been applied to overall performance. In Iowa, for example, the Board publishes a group of ratios for the 24 Iowa utilities it regulates which it views as indicators of managerial efficiency. During a rate case, the regulator evaluates the company's ratios -- in part by comparing them to the remaining utilities under its jurisdiction -- and may raise or lower the company's rate of return at its discretion. The factors for both gas and electric distribution utilities are:

- The price per unit of service by customer class and type of service.
- Operation and maintenance costs per unit of service. Low O&M costs will not be deemed indicative of efficiency if the quality of service is substandard.
- Quality of service, as reflected by customer complaints and measures of customer satisfaction.
- Top five management salaries in relation to total revenue from sales.
- Bad debt ratio.
- Innovative ideas implemented by management.
- Other factors the Board deems to be relevant.

[1]In this context, it is interesting to note that when we sought details on the sharing mechanism for a cost underrun, the information was difficult to obtain, since the probability of underrun had been virtually nil.

For electric utilities, the Board also looks at:

- Fuel cost per kilowatt-hour.
- Plant availability of the company's three most efficient plants.
- Load factor.

While the focus on the overall performance of the utility is laudable, the ability of the utility to earn an incentive return is not subject to the achievement of specific criteria and remains at the discretion of the regulator. We would caution against reliance on a multiple performance target incentive return scheme which was discretionary and likely to lead to an increased regulatory burden. Moreover, the Canadian pipeline industry is too heterogeneous to lend itself to incentive return by comparison with the performance of other pipelines.

The concept of incentive return has been discussed previously before this Board in the context of risk sharing applicable to capacity utilization. Since the operating characteristics of pipelines are such that the high utilization is a key factor in achieving low unit cost, it may have merit.

The notion of sharing the risk of underutilization of capacity was broached by the Pipeline Review Panel in 1986 when it stated in its report,

> "Because of the need to operate pipelines at the lowest cost, there should be an incentive to encourage pipeline companies to operate at the highest practical efficiency. Federally regulated natural gas pipelines now receive the same rate of return, irrespective of throughput. The Panel believes that the return on equity should be related to the degree of use of transportation service capacity." (pp. 18-19).

The issue arose again in TCPL's GH-5-89 facilities application, when the company proposed a risk sharing scheme to address the risks of underutilization of capacity which might result from the expansion to serve markets in the U.S. Northeast. The return scheme provided for a 50/50 sharing between shareholders and ratepayers for increases/decreases in the utilization factor from a target, subject to a floor which would maintain the interest coverage ratio above 2.0 times. In its Reasons for Decision, the Board rejected the risk sharing scheme essentially on the grounds that parties were unprepared for such a broad proposal and the implications of the risk-sharing scheme were not fully examined at the hearing.

In light of the Board's recent decision on the "Blackhorse Extension" (GH-R-1-92) to put TCPL at risk for underutilization of those facilities, in conjunction with the legitimate goal of optimizing utilization of facilities, it may be timely to revisit the issue of an incentive return scheme or risk sharing mechanism to promote a high utilization factor.

As noted in Section III, a key assumption underlying the fair return under the present regulatory framework is the implicit social contract between the regulator and the utility that the latter will be given an opportunity to recover the capital invested and earn a reasonable return on the investment, provided the regulator has found the capital expenditures to have been prudently made and approved their inclusion in rate base. The risk of under-utilization of facilities is not reflected in the traditional return allowance, unless that risk is specified at the time the construction permit or certificate of public convenience and necessity is granted.

We have previously noted that Canadian gas pipelines have raised about $13 billion of capital at relatively low rates on the basis of investor perception that the regulatory framework provides a high assurance of recovery of capital costs. To place the recovery of capital at risk for under-utilization would be regarded as a major change of the premises on which the capital was placed, which would have a significant adverse impact on the future cost of raising capital.

The implementation of an incentive return scheme for return on capital (specifically, return on equity), such as the mechanism delineated in GH-5-89, must also recognize that there will be an increase in the cost of capital, reflecting (1) the increased uncertainty regarding future earned returns; and (2) the uncertainty regarding the specifications of the scheme itself, e.g., the probabilities of exceeding or falling short of the targeted utilization factor.

In assessing the potential operational efficiencies to be gained by shifting the risk of underutilization of facilities to the pipelines, it is necessary to recognize:

(1) The increased risk inherent in the scheme may raise the appropriate equity ratio of the pipelines, increasing the capital costs to be borne by ratepayers at the target utilization factor.

(2) Acceptance of the relatively high load factor at which the pipelines currently operate as a baseline renders a symmetric ability to achieve or fall short of the allowed return virtually impossible.

(3) The application of the scheme to all facilities, irrespective of their likelihood of operating at a high load factor, would be regarded as unfair by those who consistently took deliveries at high load factors.

(4) The application of the scheme only to new facilities would essentially require the maintenance of two separate rate bases and the application of different returns to different markets, which could result in different customers paying different rates for essentially the same service. The Board, in its GH-5-89 Reasons for Decision noted that, given its views on the integrated nature of the TCPL system and the rolled-in tolling methodology that "it would not be appropriate to implement a risk-sharing scheme that would apply only to certain markets or facilities and not to others." (p. 36).

(5) The determination of an appropriate target utilization factor from which the increments and decrements of return are to be applied is dependent on an uncertain forecast of future contracted utilization rates. The use of a target which reflects a longer term outlook for utilization may ultimately lead to a disincentive to invest due to the risk that the incremental market load factor may skew the probabilities toward underachieving the required return.

(6) If the utility meets or exceeds the target in a number of consecutive years, with no shortfalls experienced, the risk inherent in the scheme may be discounted and the return applicable to the target load factor reduced.

Given these considerations, in our view, an incentive return scheme applied to capacity utilization would only be warranted if the pipelines seek to undertake projects which, on a priori basis, entail significantly greater risk of underutilization than those which are attributable to the volumes currently flowing, thus measurably increasing the overall risk of underutilization on the system.

4. Zone of Reasonableness/Profit Sharing

"Zone of reasonableness" and "profit sharing" incentive mechanisms are schemes of return regulation which adjust rates, or the revenue requirement, to limit the profitability of utilities, yet at the same time provide the ability to earn profits up to a specified level. The cited benefits of the approach are: (1) incentives for the utility to reduce costs to earn at the upper end of the range; (2) benefits to customers from pass through of cost savings above the range; and (3) decreased regulatory burden through less frequent tolls proceedings.

The term "zone of reasonableness" arises from the notion that there is not a single "correct" rate of return; a reasonable return falls within a range. If the reasonable range is determined to be 2 percentage points, rates are typically set at the mid-point. If the utility is able to earn at the top of the range, either through increased sales or lower costs, no tolls proceeding would be required to lower rates. On the other hand, the utility assumes the risk that if it earns at the bottom of the range, there would be no tolls increase to raise the earnings level to the mid-point of the range. If the utility return lies below or above the range, a rate (or revenue) increase, or decrease, could be requested through a tolls proceeding, or take effect automatically, as the result of the filing of a revenue/cost study.

The "zone of reasonableness" approach does not necessarily assure that the utility would permanently retain any efficiencies gained; an authorized rate decrease could either require a reduction in rates sufficient to equate utility earnings to the top of or to the mid-point of the range.

The CRTC's approach to regulation of the interprovincial telephone companies has essentially been on a "zone of reasonableness" basis.[1] The telcos' allowed rate of return typically lies in a one percentage point range; in recent years rate reductions have been periodically approved by the Commission which have kept earnings within the approved range, and which have avoided time consuming rate proceedings. Bell Canada, for example, has not undergone a general rates hearing since 1987.

"Profit sharing" is a frequent adjunct to the "zone of reasonableness" approach, now used commonly for U.S. telephone companies. "Profit sharing" allows utilities to retain a percentage of profits in excess of the upper bound of the "zone of reasonableness",[2] with the customer share reflected in lower rates. The profit sharing approach has been applied to both ends of the range; it has been applied to the lower end by limiting the percentage of the deficiency in return which the utility is allowed to pass through to the customer.

Neither the zone of reasonableness nor the expanded profit sharing approach requires a departure from cost of service regulation; both are compatible, however, with price level regulation or with pricing flexibility (e.g., banded rates). For example, profit sharing has been used in conjunction with price cap regulation by the FCC for local exchange telephone

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[1]The NEB has applied a "trigger mechanism" to Interprovincial Pipeline, which requires that the company file an application for new tolls when its rate of return on common equity is expected to exceed the most recently approved level by more than 2 percentage points. The trigger mechanism has no lower boundary although the Board stated that a 2 percentage point range above and below the allowed return is an appropriate range for determining the need for adjustment of tolls; however, the fact that IPL is earning below the trigger point does not prevent parties from seeking a review of the tolls (<u>Reasons for Decision</u>, June 1992, pp. 89-90).

[2]The range of returns within which the utility will be allowed to retain 100% of the "gains" or absorb 100% of the "losses" is sometimes referred to as the "dead band".

companies. In this case, the extent to which the companies are permitted to retain profits in excess of the upper end of the range is dependent on the magnitude of the mandated productivity gain offset to rate increases they are willing to accept. Agreement to a smaller potential increase in rates (i.e., a larger productivity offset) allows the telcos to retain a larger proportion of "excess" profits.

Profit sharing has also been used in conjunction with cost of service regulation and combined with an incentive mechanism for O&M costs under a three year settlement plan for a gas distributor, Michigan Consolidated Gas. Briefly, MichCon agreed in 1990 to increase its O&M expenditures by less than the rate of inflation for each of the subsequent three years, with the extent of the allowed increase tied to the actual CPI (e.g., 0% of the first 2% increase in CPI, 80% of the next 14%), if its return fell in the range of 12.25-14.25%. If the return fell between 14.25-15.25%, the O&M increase was reduced proportionately to the "excess" earnings; for a return in excess of 15.25%, there was no increase in O&M was permitted. For returns above 15.25%, the company was allowed to retain 50% of the excess; for returns below 12.25%, only 50% of the deficiency would be recovered from customers.

Profit sharing has also been implemented in conjunction with performance targets and "marketbasket regulation". In Mississippi, a weighted average of seven performance indicators is used to assign a utility to one of five performance classes. Its earned return is then compared to the cost of equity of other utilities with similar bond ratings. If the earned return is outside a "dead band" of two percentage points, the utility's rates are adjusted to bring the return to the mid-point of the dead band, unless the utility is in the lowest or highest performance category. If the utility is in the highest performance category, the rates are adjusted to bring the return only half-way back to the mid-point. A symmetrical upward adjustment is made if the utility is in the lowest performance category.

We are of the view that, in general, a "zone of reasonableness" alternative to the allowed rate of return, in conjunction with the remaining facets of the current regulatory model, could provide some improvement in the area of operational efficiency -- by providing an additional incentive to reduce costs -- and of reducing regulatory cost, by potentially reducing the number of tolls proceedings. However, several caveats apply:

(1) The zone should be wide enough to provide adequate incentive for management to attempt to reach the upper end;

(2) The lower end of the zone should not lie below the "bare-bones" cost of attracting capital, with the upper end potentially reflecting a normal level of returns of low risk industrial companies;

(3) The width of the zone should be wider than the potential for over- or under-earning implicit in fixed toll rate design, provided the latter is relatively narrow and falls within the range specified in (2). It should also provide a symmetric opportunity to over- or underearn;

(4) The methodology should be consistent with the rate of capital additions and the concomitant increase in throughput. For a pipeline with a growing rate base, the "zone of reasonableness" approach may only allow the pipeline to earn at the bottom of the range, yet preclude it from requesting a rate increase because the earnings fall within the range. Such a result would fail not only the fairness criterion, but the obligation to provide the utility an opportunity to earn a fair return. Moreover, it would fail the operational efficiency criterion, as an inability to earn at least the mid-point of the range would constitute a disincentive to make economic capital investments; and,

(5) The pipelines and intervenors should retain the right to petition for changes in the parameters due to changes in the outlook for capital expenditures, capital costs and significant changes in business and financial risks. At the same time, unless the number of tolls proceedings is indeed reduced, use of the zone of reasonableness method adds little incentive to reduce costs, since, absent an additional mechanism for profit sharing, all economies are passed to the ratepayer at the subsequent hearing.

The above considerations suggest that the applicability of the methodology to an individual pipeline should be tested by means of simulating various likely scenarios of growth and utilization factors to determine if an appropriate zone exists and the likelihood of avoiding a tolls proceeding for a period of at least 2-3 years.

With respect to the profit sharing adjunct, we note that, except for a single instance, profit sharing has been applied only to telephone companies. In these cases, profit sharing may be viewed as a compromise between no profit constraint and the more typical utility profit ceiling, in recognition of the spectrum of competitive forces experienced by the telcos in their various markets. For the one gas distributor case, the profit sharing was tied to the use of a cost efficiency mechanism for O&M costs.

In view of the implicit limitation on profits imposed by the toll design, we believe a profit sharing adjunct to the "zone of reasonableness" approach is unnecessary and could adversely impact on safety and reliability.

5. Banded Rates

Banded rates are an incentive mechanism which, by establishing upper and lower limits for tolls, targets the goal of allocative efficiency. Within the band, the utility has the flexibility to adjust prices to meet competition, to preclude uneconomic bypass, and to promote optimal capacity utilization. The concept of banded prices has been proposed for markets which are neither totally monopolistic nor totally competitive. The band limits are intended to protect ratepayers from the exercise of market power on the upside and to prevent predatory pricing and/or cross-subsidization on the downside.

The use of banded rates may be viewed as a step toward price level regulation. The pricing limits can be determined within the confines of cost of service pricing; however, the intent of the mechanism is a departure from fully distributed cost pricing. If the bands are originally based on embedded cost pricing principles, but are then permitted to move automatically to a new upper band, or cap, based on an index, the prices are decoupled from embedded costs, and the "banded rates" approach effectively constitutes a form of price cap regulation.

Gas distributors in both the U.S. and Canada have had market-responsive rate options for industrial sales loads subject to competition since the mid-1980s. A 1990 survey by the American Gas Association of its membership showed that 78 and 67 gas distributors respectively had flexible and discounted interruptible transportation rates; 46 and 38 respectively had flexible and discounted firm transportation rates. The range of the rates for interruptible transportation has frequently been the variable cost plus a small (judgemental) contribution to fixed costs and the fully allocated firm transportation rate.

Under Order 436, the FERC authorized a form of banded rates (minimum and maximum rates) for interstate pipeline transportation services, with the lower limit equal to the unit variable cost, and the upper limit equal to the fully allocated cost of transportation, reflecting what had been its long-standing policy of using embedded costs to determine pipeline transportation rates.

In December 1991 the FERC rejected an incentive proposal by Viking Gas Transmission which sought to set rate bands for firm transportation to efficiently allocate its capacity. In its findings, the FERC concluded that the caps were set so high as to be tantamount to market based rates, and that FERC policy has been to allow market based rates only if the pipeline can demonstrate that it lacks market power.[1] The Commission noted that it was considering incentive regulation and was therefore dismissing Viking's proposals without prejudice. However, in its Proposed Policy Statement on Incentive Regulation (March 13, 1992), if a

[1]57 FERC 61, 417 (1991).

pipeline proposes an incentive rate, the FERC stated that it would require a quantified estimate of consumer benefits compared to cost of service regulation, i.e., a comparison of cost of service rates to the proposed incentive rates. In this context, FERC cited its own Viking decision, noting that the pipeline's proposal had seemed to guarantee that future rates would be higher than under embedded cost regulation. FERC's concern in this regard suggests that the Commission expects that incentive regulation will generally produce lower rates for non-competitive markets than cost of service rates. This is to be expected for pipelines with excess capacity; however, for fully utilized pipelines which are significantly depreciated and with a queue for service, it is a somewhat surprising conclusion.

However, unless the regulator is willing to allow transportation rates to rise above the fully allocated cost level,[1] as long as there is a queue for service, the fixed toll rate design does provide the most efficient approach to allocation of firm capacity. Since the fully allocated cost represents the maximum rate the Board is willing to allow and the capacity is fully contracted, there is no need for a lower band for firm transportation. However, for pipelines which operate at less than 100% utilization, one should consider providing incentives to move interruptible volumes. If some pricing flexibility were allowed in the form of the ability to discount rates to close to variable cost, it should be accompanied by the ability to retain a share of the revenues from interruptible transportation.

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[1]It has been suggested by some economists that the upper end of a band for rates be set at replacement cost, long run marginal cost or a combination of historical/reproduction cost. While these rates might allocate existing capacity and eliminate the queue, the "excess" profits which would result would likely be unacceptable. Moreover, these approaches for the most part are not practical since the calculation of the values is difficult. The concept of stand-alone cost, for example, was suggested to the FCC as an upper limit for telco rates. (The stand-alone cost is that cost which would be incurred by a potential competitor to serve a specific market). The concept was rejected by the FCC in favor of price caps, due to the theoretical nature of the "stand-alone" concept as well as the likely excessive values which would be produced.

6. "Yardstick" and "Marketbasket" Regulation

"Yardstick" and "marketbasket" approaches to regulation may be characterized as forms of regulation which compare a given utility to other companies with similar performance and risk characteristics, and use those comparisons to index the company's costs or reset the overall price level.

The term "yardstick" regulation refers to regulation of prices on the basis of the average costs of comparable utilities, rather than on the basis of a utility's own costs. By basing prices on comparable firm costs, firms are compelled to act as if they were operating under competition. Firms with above average costs will be forced to reduce costs to the average to earn a normal rate of profit. In the long run, the average cost level would converge with "least cost" levels on the cost curve.

"Marketbasket" regulation is conceptually similar, except that it focuses on the returns of comparable firms, rather than costs. Under marketbasket regulation, a utility's profits would be determined to be "excessive" if the return (which might be defined as the book or stock market return) was in excess of that of a comparable group. If excess profits were determined to exist, rates would be reduced.

With respect to cost focused "yardstick" regulation, the concept arises from the notion that competition will ensure minimization of economic costs. Thus, if a utility is forced to price on the basis of average industry accounting costs (as a proxy for economic costs), its costs will be forced to the industry average, and ultimately, the industry average and minimum costs will converge. However, since only accounting costs, and not economic costs, are directly measurable, the implementation of "yardstick" regulation would require similarity of market structure (similar supply/demand conditions), in order to produce similar capacity needs, and also require homogeneity of asset vintage. Only then could one begin to approach any degree of comparability. This is simply not realistic. The markets of the various Canadian pipelines are vastly different in terms of geographical terrain, asset vintage, end use market characteristics, growth patterns and size.

With regard to "marketbasket" regulation, it is intended to afford greater pricing flexibility than cost of service pricing, while subjecting the utility to a profitability constraint. The profit constraint would be based on earnings or market performance of comparable firms. In effect, except for the pricing flexibility provision, it is little more than a reincarnation of comparable earnings applied to utilities, a method for estimating the allowed return under cost of service pricing long discredited due to circularity.

Alternatively, the marketbasket approach envisions judging the reasonableness of the utility's profitability on the basis of relative stock market performance. The barriers to reliance on relative stock market performance as a measure of excess or inadequate returns are simply too great, due to:

(1) An inadequate number of Canadian publicly traded, directly comparable firms;
(2) No direct link between the level of earnings and level of market return to be used as "yardstick";
(3) Movements in stock market prices reflect factors other than recent earnings; and,
(4) Movements in market prices reflect all operations, not just regulated operations.

On these grounds, we believe no further pursuit of these alternative approaches to regulation is warranted.

7. <u>Price or Rate Cap Regulation</u>

Price cap regulation is a departure from traditional cost of service regulation, under which, for a given period, the increase in rates for services provided is subject to a cap based on the rate of inflation less a pre-determined percentage intended to represent a level of efficiency or productivity gain. The cap can be imposed on individual services, on "baskets" of services, or as a weighted average rate (i.e., individual rates can fluctuate as long as the ceiling for the weighted average is not exceeded). Price cap regulation can contain a revenue constraint by establishing a ceiling which the weighted average of all prices may not exceed; alternatively, it may include a profit constraint, under which returns above a certain level are returned to ratepayers. It may also put constraints on the extent which individual service prices can move up or down in a given year to impose some degree of rate stability and, in some instances, to preclude predatory pricing.

Price cap regulation has been applied primarily to telecommunication firms in the U.S. and Great Britain and to British Gas for its "core" market.

Under price cap regulation, the direct link between rates and costs which exists under rate of return regulation is eliminated, with the expected benefits being that:

(1) ratepayers may experience a reduction in real rates, assuming the productivity gain exceeds the rate of inflation;
(2) the utility has the incentive to reduce costs between rate reviews, since all efficiency gains in excess of the productivity offset flow to shareholders;
(3) the utility has increased pricing flexibility;
(4) the incentives for cross-subsidization are reduced; and,
(5) regulatory costs are reduced as price cap regulation eliminates the need for frequent in-depth regulatory reviews.

As price cap regulation is a significant departure from cost of service regulation, we present a criterion by criterion assessment of the methodology.

Operational Efficiency

In theory, price cap regulation should produce both technical and dynamic efficiency because (1) the price cap imposes on the utility increases in rates which are less than the rate of inflation; (2) any cost reductions in excess of the productivity gain embedded in the price cap accrue to the shareholders at least until a subsequent rate review; and (3) the weakened link between rate base and profits eliminates the incentive for utilities to overinvest.

In practice, for Canadian gas pipelines, the potential operational efficiency benefits from price cap regulation to either ratepayers or investors are very much a function of a pipeline's individual circumstances. For a pipeline with a declining rate base, or a pipeline operating at a low utilization factor (without a revenue constraint in addition to price caps), the potential for windfall profits is relatively high. Exogenous increases in demand (not due to management efforts to improve utilization) may result in lower unit costs and higher profits.

For pipelines operating at high utilization factors, and facing growth in demand, the price caps may not cover the cost of new facilities and produce a disincentive to capturing new markets, resulting either in a sub-optimal level of capacity or the need for redetermination of the cap each time a major facilities expansion is undertaken.

With respect to operating and maintenance cost efficiencies, the imposition of a productivity gain encourages the minimization of costs, but potentially at the expense of safe and reliable service, if the mandated productivity offset is set too high to permit the utility to earn a compensatory return.

The size of the productivity gain to be imposed is a controversial issue, since there is no widely accepted method for determining what productivity gain may reasonably be expected.[1] The traditional measurement of productivity relates cost to output. For a pipeline,

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[1]In this regard, it is notable that the British Gas price cap formula operated from 1986-1992 with a 2% offset; it has recently been increased to 5%.

output is synonymous with throughput. If a pipeline increases its utilization factor from, for example, 80% to 88%, it has improved its productivity. However, the rise in utilization rate may be due to exogenous factors unrelated to managerial efforts. In theory, the productivity offset should distinguish between managerial efforts (e.g., increases in demand due to managerial efforts to attract new industry into the service area or the provision of a given level of service at lower cost) and exogenous events (e.g., a rise in the population). Productivity gains which are unrelated to managerial efforts but which flow to shareholders in the form of higher returns are likely to call into question the credibility of the regulatory scheme. However, such distinctions are partly judgemental and likely to be controversial.

The cost index used to set the price cap is also likely to be controversial, though perhaps less so than the productivity index. Some proponents of price caps have suggested an inflation index tied directly to the utility's costs. For an individual pipeline, it might even be suggested that the index be proportionately weighted by the different components of the pipeline's costs. In the extreme, for a pipeline with a declining rate base, the result might be a negative index. Such an approach would effectively negate the whole purpose of price cap regulation: to decouple prices and the pipeline's own costs.

A more realistic approach to the cost index has been proposed for U.S. pipelines, namely a cost index based on a more general indicator of prices, the CPI or GDP deflator. Even these indices fail to consider that for some Canadian pipelines there remain significant costs beyond their control, e.g., transmission by others and property taxes. These presumably could be handled in a separate adjustment to the price cap.

In assessing the applicability of price cap regulation to Canadian pipelines to achieve operational efficiency, it is important to recall that operating efficiency has three distinct aspects:

(1) Efficiency in operating and maintenance costs;
(2) Efficient utilization of plant; and,
(3) Efficient capital costs.

Price cap regulation is likely to increase the cost of capital, leading to higher base rates than exist under the current regulatory framework; mandated efficiencies in the operating and maintenance cost area will produce incentives to sacrifice reliability in favor of profitability. If the key objective is to foster optimal utilization of facilities, then the increased cost of bearing the higher risk inherent in price cap regulation may more than offset the otherwise lower unit costs arising from higher throughput. Optimal utilization of facilities is a legitimate principal goal if significant underutilization exists, as it does with many U.S. pipelines and electric utilities. However, since Canadian pipelines are currently operating with high utilization rates and increasing demand for capacity, the adoption of a scheme which mandates productivity improvements is counterproductive, discouraging penetration of new markets, encouraging a diminution of safety and reliability, while raising the cost of capital.

Technological Innovation

One of the claimed benefits of price cap regulation is the encouragement of the pursuit of technological innovations which reduce production costs or result in additional services, because a share of the productivity gains flow to shareholders. For telecommunication firms, where technological advances continue to produce real cost reductions and new product development, the need for an incentive to pursue innovation is clear; for Canadian pipelines with high utilization factors and the significantly lower probability of important technological breakthroughs, the need for, or the ability to achieve benefits from, such an incentive is not as clear cut. As the Chairman of South California Gas put it, "There is no microprocessor in our future that is going to enable us to double pipeline capacity or use our distribution system to deliver more than one product."[1]

[1]R. D. Farman, "Should Some Type of Incentive Regulation Replace Traditional Methods for Regulating LDC's?", Record of Proceedings: Conference on State Regulation and the Market Potential for Natural Gas, U.S. Department of Energy and NARUC, February 1992.

Safety and Reliability of Service

Since price cap regulation requires reductions in unit costs in order to increase shareholder earnings, there is an incentive to sacrifice safety and reliability of service in order to cut expenses (e.g., to defer maintenance or to cut the number of safety inspectors), unless standards of service are specified and monitored and a penalty mechanism is in place for failure to meet the standards. Telecommunications firms have traditionally been subject to service standards; the technology itself provides a built-in monitoring system. For pipelines and gas distributors, the absence of such standards suggests that, in these industries, service standards are less easily defined and monitored cost-effectively. To our knowledge, no specific proposals have been put forth to ensure maintenance of service standards in connection with price cap regulation for these industries.

Allocative Efficiency

A key benefit of price cap regulation is the inherent price flexibility, which allows utilities some ability to respond to changes in demand and competitive conditions. The subjection of rates to ceilings, rather than basing rates on costs, is also said to eliminate the incentive for cross-subsidization, i.e., shifting costs from competitive to monopoly services. In practice, floors or limits on annual changes (up or down) have been required in jurisdictions where price cap regulation is utilized, in order to prevent predatory pricing.

The use of price caps to achieve allocative efficiency in the telecommunications industry is in part a function of the mixed monopoly/competitive nature of the business as well as the plethora of potential service offerings. Imposition of price caps in regulated communications markets characterized by market power, and deregulation in competitive markets, is able to offer a modicum of rate protection to customers of monopoly services, price flexibility where some degree of competition exists, and the ability to compete in truly competitive markets, while potentially eliminating the need for detailed separations studies for all of the individual services offered.

The Canadian pipeline industry structure is quite different. While there is significant inter-fuel competition in Canadian markets, as well as the threat of by-pass, and substantial intra-modal competition in U.S. markets, the potential number of service offerings is significantly less extensive. Therefore, while some pricing flexibility may be warranted for pipelines, this may be achieved by a less radical departure from the current regulatory mode than price cap regulation.

Fair Return on Investment

The extent to which the opportunity to earn a fair return on investment is offered under price cap regulation is a function of (1) the symmetry of probabilities of achieving versus falling short of the investors' required return reflected in the price cap formula; and (2) the underlying assumptions regarding the required return embedded in the "base rates".

With respect to the former, if the combination of the productivity gain and the price increase intended provide little or no potential to exceed the required return (e.g., mandated productivity requirements when facilities are fully utilized), but no effective floor on the return, the utility's opportunity to achieve a fair return has been effectively eliminated. With respect to the latter, if the "base rates" are those most recently approved by the Board under cost of service regulation, they will fail to reflect the increased level of risk to which the shareholder is exposed; the ability to earn a return commensurate with the new level of risk may be impaired.

Predictability and Consistency

Two questions arise from this criterion:

(1) How predictable are the rates under price cap regulation compared to cost of service regulation?

(2) How will investors, whose expectations are based on consistency of the regulatory framework, react to the change?

Under "perfect" price cap regulation, i.e., a methodology under which a consistent formula will be applied year after year, price changes are relatively predictable; on this basis alone price cap regulation might provide some benefits over cost of service regulation to ratepayers whose main interest is predictability, since price increases are limited by the cap. However, price cap regulation represents, in a sense, an experiment whose elements are subject to adjustment as experience with the methodology progresses and which ultimately is subject to reversal if the experiment does not provide the intended benefits. For example, if the formula for price caps is subject to review every three or five years, or the regulator decides to resume cost of service regulation, substantial rate changes may be imposed at that juncture.

With respect to the reaction of investors, a switch to price cap regulation would be deemed a radical departure from the present mode of regulation; the uncertainty regarding eventual outcomes may lead potential new investors to demand significantly higher returns for new pipeline investments.

Public Policy/Fairness

Depending on which aspect of public policy is regarded as most important (e.g., conservation vs. resource development), price cap regulation may be either more or less compatible with the public policy than the present mode of regulation.

The issue of fairness to all parties would likely be viewed in part in the context of the level of returns to shareholders, which indirectly subjects the utility to rate of return regulation, and the same controversies as are faced in the determination of a fair return under the current method.

Rates of return which are intuitively viewed as excessive for a utility would not be publicly acceptable. The FCC has handled this situation in its regulation of dominant local exchange carriers by combining price caps with profit sharing, under which profits above a certain level are shared with ratepayers. Telephone companies have been offered a choice of productivity offsets in their price cap formula; the higher the productivity offset, the greater the proportion of profits above a certain level the company is allowed to retain. This approach requires not only determination of a "zone of reasonableness" for the returns on equity to be retained by the utility, but also the appropriate sharing proportions of returns above the upper end of the range.

A further aspect of the fairness question in price cap regulation is the implicit change in the basic underlying premise of the current rate of return regulation, namely that ratepayers expect to compensate the utility shareholders only for the cost of assets devoted to the public interest. As the rate base depreciates, rates decline. A price cap formula may invalidate this premise. Although real rates would decline, nominal rates could continue to increase, probably causing some parties to claim that the utility was being allowed to overrecover its investment.

Regulatory Cost

Price cap regulation is intended to reduce the regulatory burden. In depth reviews are typically envisioned at intervals of three to five years. The right to request more frequent reviews by any affected party is nevertheless preserved. The actual regulatory cost incurred under price cap regulation is likely to be a function of the degree to which the "spirit" of the regulatory mode is respected by all parties.

Conclusion

On balance, we regard price cap regulation as (1) a radical departure from cost of service regulation, which is likely to significantly increase the cost of capital for pipelines; (2) a currently unnecessary alternative in light of the high utilization rates of Canadian pipelines; (3) a potential cause of windfall profits for some and inadequate returns for others, depending on rate base growth; and (4) a potential source of considerably greater controversy and regulatory burden than the current methodology.

V. RECOMMENDATIONS

Our analysis of the effectiveness of current regulatory framework and potential effectiveness of alternative regulatory mechanisms has led us to the following conclusions and recommendations:[1]

(1) The NEB's regulatory framework is the principal factor which has allowed Canadian pipelines to operate at a relatively high degree of financial leverage and to attract capital at relatively low rates in comparison to their U.S. counterparts. Since the cost of capital is a key element of the revenue requirement, any changes to the current system should be made gradually and consider the potential rise in the cost of capital not only for the existing pipelines but also with regard to the implication of a change in the regulatory mode on the cost of attracting capital for major new projects.

(2) As a step toward streamlining the regulatory process, we recommend that the Board pursue the concept of generic rate of return. A benchmark rate of return could be set in a single hearing during which all expert evidence would be heard. At the same time, a formula would be sought to determine automatic annual changes to the return. In our view, this formula should be based in large part on the risk premium test; i.e., tied to changes in long-term interest rates, and should recognize the inverse relationship between interest rates and the equity risk premium. A reevaluation of the benchmark and formula would be triggered if interest rates fall outside a range of approximately 8-12% or if an agreed upon period has transpired (e.g., 3 years). Capital structure issues and any company-specific circumstances regarding business or financial risks would be dealt with in the individual pipeline's tolls proceeding.

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[1]These recommendations are made without considering whether the current critical posture of the producing industry toward the Board's rate of return regulation creates an environment which is conducive to incentive regulation, considering the essence of any incentive scheme would provide the pipelines with an opportunity to earn higher returns than those now allowed by the Board.

(3) Our analysis indicates that an incentive mechanism for operating and maintenance expenses is generally unwarranted in light of the relatively small fraction of the revenue requirement that they account for, and the irreducible nature of the preponderance of the total. However, if the Board believes that a cost efficiency mechanism is necessary, we suggest the following:

For pipelines whose O&M expenditures are not expected to outpace inflation due to rate base growth, O&M expenses could be indexed to inflation. To provide an incentive to minimize actual outlays, a sharing mechanism from the base level (adjusted periodically for "exogenous" factors) could be implemented, under which the pipeline could capitalize its share and amortize the savings over a period of time.

(4) With respect to capacity utilization, we believe an incentive return mechanism would potentially promote operational efficiency if (1) current capacity is significantly underutilized or (2) if potential capacity additions pose a significantly greater risk of underutilization than existing capacity.

Since virtually all Canadian gas pipelines are operating at high utilization factors, it would be counterproductive to expose the shareholder to the risk of underutilization of existing capacity, since the cost of capital would rise. With respect to putting pipelines at risk for underutilization of future capacity, it should be recognized that, at present, the allowed return is not intended to compensate investors for the risk of underutilization, subject to the constraints of competition. The implementation of an incentive return mechanism would require an increase in the "baseline" return (similar in concept to the Board's IROR Risk Premium mechanism for Foothills' construction), and potentially a separation of facilities into those subject and those not subject to the mechanism. However, such an approach would be contrary to the traditionally accepted integrated system philosophy, could be challenged as unfair to different groups of ratepayers and would be administratively burdensome.

(5) We believe a "zone of reasonableness" approach to rate of return could further streamline the regulatory process and provide an incentive to pipelines to cut costs

to earn at the upper end of the range. The "zone of reasonableness" should only apply to pipelines with no major capacity expansions, so that the probabilities of exceeding and falling short of the mid-point of the zone are not biased toward the lower end of the range.

The "zone of reasonableness" approach is compatible with a generic rate of return formula; the limits of the zone for pipelines operating under that approach could be reset when the benchmark return is reset.

(6) With respect to increased allocative efficiency, increased pricing flexibility for interruptible volumes using banded rates, with a sharing of revenues from increased throughput, should be considered. For firm transportation, it is our opinion that, as long as a queue exists for transportation, there is no reason to introduce the concept of banded rates, since the fixed toll design would most efficiently allocate capacity unless the Board would be willing to allow the upper end of the band to rise above the fully distributed cost toll.