MILLENNIUM

CAMPUT 2000

National Overview of Regulatory Issues

August 2000

Inuvik, Northwest Territories

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Foreword

This National Overview of Regulatory Issues is a formal vehicle for communication among CAMPUT members. The summary reports from member tribunals included in the National Overview reflect significant regulatory decisions made in each jurisdiction and emerging regulatory issues facing each member tribunal over the past year.

We thank all the member tribunals for their submissions and contributions and all those involved in the preparation of this Overview.

We hope you find the Overview of interest and benefit to you. It is also available on the National Energy Board website. We would very much like to hear your comments and suggestions about the report and its content at our meeting in Inuvik on August 22.

CAMPUT
2000

Northwest Territories Public Utilities Board

Summary of Significant Decisions and Emerging Issues.

1999 was not a particularly busy year for the Northwest Territories Public Utilities Board. The major matter before the Board was a General Rate Application filed by Northland Utilities Limited for the 1999 and 2000 Test Years. Northland serves a number of communities in the south Mackenzie region. Phase I of the Application was dealt with subsequent to a negotiated settlement between the interested parties.

The Phase II portion of the Application was complicated by a request from the Hamlet of Fort Providence that it be established and recognised for rate making purposes as a separate zone. The Hamlet had for many years been part of a 'Rate Zone' that included two smaller communities. The Board was concerned that approval of the request would create rate shock in the two small communities. The utility was directed to provide a mechanism for adjusting rates over time to mitigate the impact. Subsequently, the Board approved the rate zone changes and revised rate schedules.

The Board in its previous submissions to the Regulatory Affairs Committee had expressed its concern over the need to jointly regulate the Northwest Territories Power Corporation ("NWTPC"), the major utility in the north, with the Nunavut Public Utilities Board.

Legislation was proposed to enable each Board to enter into an agreement for the establishment of a joint division to deal with applications filed by NWTPC. The proposal was accepted and legislation was put in place, mirrored in both jurisdictions.

However, as a result of the Government of Nunavut's decision to split the utility, effective April 1, 2001, the two Boards are not expecting any major rate cases until after the split takes place. Meanwhile, we have dealt with a number of minor matters, such as Project Permit Applications and a Fuel Adjustment Clause on a joint basis.

NWTPC's facilities include hydro electric and diesel generation plants, transmission systems, and numerous isolated distribution systems. It exists in a unique operating environment with extremely low customer densities, unique climate and consequential logistic challenges as well as the lack of an integrated transmission system. It operates 46 separate power systems in both territories serving a total population of approximately 58,000 located in an area of 3.2 million square kilometres. As NWTPC's systems are isolated and unconnected, each must be planned for and operated independently. Many proposals have been made in the past 10 - 12 years with respect to the creation of rate zones to reduce the impact of major capital expenditures in a community. None of the proposals has received support from participants in proceedings before the Board and as a result there now exists 46 separate rate zones.

Two communities are now requesting proposals for the provision of electrical power by other utilities. We believe that one of the communities is merely testing the water. The other community has gone farther, and we understand that they have selected a new supplier, subject to the approval of local residents through a plebiscite yet to be held.

The Board will be faced with examining rate proposals from a utility new to the north, using, we understand, some form of distributed system. We will be concerned about new rates that the Mayor of the community is suggesting will be lower. How this will be achieved given that a totally new plant is to be set up, without compromising service quality, remains to be seen. The NWTPC provides for an installed capacity of 110% of peak load in order to ensure the supply of power in the harsh weather conditions we experience in the NWT.

NWTPC also has standby units that can be transported rapidly in the event of a system failure. For example, in the case of the total loss by fire of the power plant in Sanikiluaq, a small community in the Belcher Islands, Hudson Bay, they were able to restore power within 32 hours.

In the event that the new supplier meets all the Board's criteria with respect to rates, and an ability to provide safe reliable power over time, on satisfactory terms and conditions of service, then we will be faced with the issue of NWTPC's stranded investment.

The Board is conducting a Operational and Strategic Review of its operations. At present the Board is managed by a full-time Chairman, with four part time members. The Chairman is supported by the Board Secretary, a full-time administrative position. The Board no longer has in house technical or legal staff, such services are obtained from outside firms on a contractual basis.

The utilities currently under the jurisdiction of the Board are in a position where the degree of regulatory oversight has been diminishing slowly over time, as a result the Board's workload has decreased significantly in the past few years.

If the Board's workload does not increase as a result of being given additional responsibilities, such as the environment, water and sewage rates then changes to the Board's structure and operating procedures may be warranted to reflect the reduced demand on the Board's resources.

British Columbia Utilities Commission

In 1999/2000, the Commission began a review of its Negotiated Settlement Process Guidelines. The Commission adopted new service options for BC Hydro industrial customers and worked on development of unbundled transportation service for BC Gas customers. The Commission also reviewed a West Kootenay Power Ltd. application to upgrade its aging transmission facilities. Key issues and challenges for the Commission in the future include mitigation of high gas commodity prices for consumers, reviewing BC Hydro's revenue requirements and rates once it is again fully regulated by the Commission, and reviewing BC Gas rates including the costs of the Southern Crossing pipeline. Centra Gas is also required to file its first rate design for the Vancouver Island Gas Project.

British Columbia Hydro and Power Authority

The *British Columbia Hydro and Power Authority Rate Freeze and Profit Sharing Act* which froze BC Hydro's rates from December 10, 1997 to March 31, 2000, was extended to September 30, 2001. The Commission, therefore, did not review BC Hydro's 1999/00 revenue requirements or rates and has no plans to review the utility's revenue requirements or rates for 2000/01. The Commission is preparing to review BC Hydro's revenue requirements and rates beginning in 2001 for the period following the expiry of the rate freeze. Meanwhile, the Commission has directed BC Hydro to submit a report by June 30, 2000 that fully describes its export trade activities. Revenues from electricity trade are approaching one third of BC Hydro's total revenue.

Although the rates and fixed charge portions of BC Hydro's rate schedules are frozen, other terms and conditions of the tariff can be amended and new rates for new services can be established. For instance, the Commission has approved some new services for industrial customers such as the Price Dispatched Curtailment (PDC) program and Time-of-Use pilot programs for general service and transmission service customers. The PDC program allows BC Hydro to offer industrial PDC customers, when the market price of electricity is high, the opportunity to curtail their consumption so that the power can be sold at market. BC Hydro and the customer share in the net proceeds.

The B.C. Utilities Commission has not reviewed BC Hydro's resource plans in detail since 1995. A Minister's Order that exempted BC Hydro and its power producers from the need to obtain Certificates of Public Convenience and Necessity ("CPCN") and approvals for supply contracts was recently extended to September 30, 2001.

BC Hydro's 1999 Integrated Electricity Plan identified that the utility would require additional electricity supply to Vancouver Island by 2007. BC Hydro's preferred option appears to be a second cogeneration plant (in addition to the Island Cogeneration Project at Campbell River). BC Hydro is investigating construction of a new pipeline to deliver natural gas from the Lower Fraser Valley through Washington State and across the Strait of Georgia to Vancouver Island. BC Hydro will require approvals from the Commission to complete its natural gas fired generation projects on Vancouver Island and to deliver the requisite natural gas through a new under-sea pipeline.

West Kootenay Power Ltd.

West Kootenay Power Ltd. ("WKP") applied in November 1999 for a CPCN to upgrade its aging transmission facilities. WKP's Application followed significant power outages and surges in the summer of 1999 and the project is expected to significantly improve the safety and reliability of electrical service. Although the other regional transmission owners support the project in principle, WKP has been unable to reach complete agreement with them on interconnection with their transmission systems, and on ownership, and cost sharing. A Decision approving most of the project was released on June 5, 2000. The difficulty in reaching agreements among the transmission owners in the Kootenay region has highlighted potential benefits of a Regional Transmission Organization.

Gas Utilities

Most BC natural gas utilities filed for large rate increases in 2000, largely to recover the higher commodity cost of gas. As rates are set on a forward test year based on the forecast cost of gas, differences between the actual and the forecast cost of gas are recorded in deferral accounts. As the cost of gas has increased even faster than forecast, some utilities were accumulating large deferral account balances. In this situation, the Commission must consider whether to begin reducing the deferral account balances and, if so, how.

Direct gas sales in British Columbia have not yet penetrated commercial and residential markets. In response to requests from natural gas brokers/marketers, the Commission initiated development of an Agency, Billing and Collection Transportation ("ABC-T") tariff for BC Gas that would provide residential and commercial customers the option to purchase gas directly. In April 2000, the Commission asked marketers to confirm their commitment of technical resources to development of appropriate business processes and interfaces with BC Gas. The process continues.

In May 1999, the Commission approved BC Gas' request for a CPCN to construct the Southern Crossing Pipeline ("SCP") extending from the Alberta Natural Gas Ltd. system at Yahk to Oliver, BC. BC Gas filed an Application with the Commission in March 2000 to determine how to include the SCP costs in rates. The Commission will review the application during summer and fall 2000, and has directed BC Gas to file a comprehensive rate design application in early 2001.

Centra Gas delivers natural gas to Vancouver Island under a government initiative that requires customers to pay rates close to the cost of competitive fuels (oil, electricity). The rates are not cost-based and large cost deferrals are being accumulated. With new industrial customers joining the system, Centra Gas is required to file its first comprehensive rate design in the fall of 2000.

Negotiated Settlement Process Review

In January 1996, the Commission issued procedural guidelines for negotiated settlements, outlining the process for parties attempting to achieve negotiated agreements. In October 1999, the Commission established a written process to review the NSP Guidelines. Final comments were received in March 2000. The Commission is currently reviewing the comments and will determine how the NSP Guidelines should be revised.

Alberta Energy and Utilities Board

Regulatory Summary

This summary focuses primarily on decisions on utility applications with highlights of major energy decisions. All Alberta Energy and Utilities Board (EUB) Decisions can be accessed at www.eub.gov.ab.ca.

ATCO Electric and TransAlta Power Rates – Phase II (Decisions U99034, U99035, 2000-11, 12, 13, 15, 26)

In August 1999, Decisions addressed applications by ATCO Electric (AE) and TransAlta Utilities Corporation (TransAlta) to reallocate costs between to the various customer classes arising from the restructuring of Alberta's electric industry started in 1996. Two re-filings were required to resolve issues. Increases for individual rate classes were restricted to less than 10 % to accommodate an orderly transition towards a restructured electric industry.

TransAlta and AE's new rates did not affect shareholder's rate of return.

Electric Utilities 1999-2000 Revenue Requirements (Decisions U99099, 2000-2, 3, 4, 5, 19, 31, 32, 36)

The November 1999 Decision on TransAlta, EPCOR Generation Inc., EPCOR Transmission Inc. and ATCO Electric. Previously on May 10, 1999, the Board approved a Negotiated Settlement Agreement between AE and intervening consumer groups, which settled all issues except for three relating to terms and conditions of service.

The Board implemented processes that addressed the transition to a world of unregulated generation and retail competition commencing January 1, 2001 including some audit processes for transition accounts. A deferral account mechanism for electricity pool prices was established to keep customers and utilities in a balanced risk position from gains or losses associated with the difficulty in predicting power pool prices.

The Board increased TransAlta's integrated common equity from 40% to 41% and awarded the 9.25% on the higher allowed common equity. The Board noted that its award of 9.25% on 41% is equivalent to a rate of return of 9.40% on 40% if TransAlta chooses to keep its common equity at 40%.

The Board directed that the allowed equity rate of return (the combination of risk premium + risk-free rate) for TransAlta and EPCOR will be changed from 11.25% to 9.25% effective January 1, 1999. This change results from the Board's decision that the risk premium included in the return on invested equity for TransAlta and EPCOR should remain constant at the 1996 level of 3.5%.

Decision Report on the Independent Assessment Team's Hearing (Decisions U99073, U99113)

The Decision regarding the Independent Assessment Team's (IAT) report on the Power Purchase Arrangements (PPAs) respecting regulated generating units owned by ATCO Electric, EPCOR, and TransAlta Utilities was issued on December 30, 1999.

The IAT was appointed by the Minister of Resource Development to complete an assessment of the utilities' proposals for PPAs and to recommend a design and related set of rules for the sale of the PPAs by auction. PPAs, which are long-term, arrangements starting in 2001 and effective for a maximum of 20 years, establish the terms, conditions, and operating and commercial arrangements between the owners of Alberta's regulated electric generating units and the purchasers of the PPAs. The PPA auction will take place in July 2000.

The majority of the Board concluded that each party requesting variances failed to show that the IAT did not carry out its duties in accordance with the Act and the regulations. Similarly, it was not shown that the PPAs or other determinations of the IAT are obviously unreasonable, are not supported adequately by economic analysis or are not in the public interest. No variances to the PPAs were made.

Electric Transmission Tariffs for 1999 and 2000 (Decisions 2000-1, 24, 25, 27, 34)

The Decision on the ESBI Alberta Limited (EAL) application for approval of revenue requirements, rate design, tariffs and other regulatory matters was issued on February 2, 2000. EAL is the Alberta's independent Transmission Administrator (TA) who administers the province-wide interconnected electric transmission system, the wires of which are owned by the existing utilities. The TA is required by statute to provide buyers and sellers with non-discriminatory access to the transmission system and ensure that the system is reliable and operates efficiently.

The approved tariffs will enhance system reliability, provide incentives for transmission efficiencies, and are important steps in the restructuring and deregulation of the electric industry.

Owners of generators and load customers will share transmission system costs. This is different than today's situation where load customers are directly responsible for almost all of the costs. Owners of generators will increase their Power Pool price offers to recover increased transmission tariff costs. Load customers' higher energy costs are offset by reduced transmission tariffs.

The Board approved a market driven mechanism (the Standing Offer process) to provide financial incentives for new generators to locate in parts of the province where transmission constraints need to be addressed.

NGTL's 1999 Products and Pricing (Decision 2000-6)

The Decision on Nova Gas Transmission Ltd.'s (NGTL) application for new service offerings and related rates, tolls and charges was issued on February 4, 2000. NGTL proposed a fundamental change from its current "postage stamp" rate design that has been in place since 1980.

The Board concluded that the objective of postage stamp rates has now been accomplished. Changing market conditions and increased competition in natural gas transportation now requires a new approach.

Postage stamp rates will be replaced with a new rate design (Receipt Point Specific Rates [RPSR]) that better reflects the cost associated with distance and pipeline diameter.

The Board found that RPSR best meets accepted rate making principles and is in the public interest.

The Board directed NGTL to incorporate and to apply a Price Floor and Ceiling mechanism over a four-year Transition Period to mitigate the impact of moving away from the current postage stamp rates

The Board also approved NGTL's new facility construction proposal as filed but was not prepared to allow NGTL affiliates to participate in the construction of lateral facilities until a Code of Conduct satisfactory to the Board is in place. Additionally, the Board accepted that new Alberta receipt laterals and new Alberta delivery laterals will be included in the rate base, provided such facilities can be in service within the four months following implementation of the Board's decision. Thereafter, such facilities shall be excluded from NGTL's rate base and from its revenue requirement.

ATCO Gas and Pipelines Ltd. General Rate Application (Decision 2000-09)

The Decision on ATCO Gas and Pipelines (formerly Canadian Western Natural Gas [CWNG]) application was issued on March 2, 2000 including gas storage, supply, and accounting issues. The Board addressed capital structure, storage revenue, affiliate transactions, code of conduct and refunds to consumers.

The Board noted that changes from restructuring of the utilities, creating concerns on the relationship between regulated and non-regulated businesses. A passive expression of such concern is no longer sufficient and directed CWNG to develop a Code of Conduct for affiliate transactions. The Board provided guidance on specific areas to address.

Oil And Gas Related Decisions

Lochend Sour Gas Well Decision 99-16

On July 12, 1999 the EUB approved an application by Canadian 88 Energy Corp. for a well licence to drill a level 4 critical sour gas well in the Lochend area approximately 11 kilometers west of Calgary.

Although the Board believed that the risks associated with the well is representative of normal industrial risks accepted by society and that it could be drilled safely, it was not satisfied with the state of preparedness of Canadian 88. Therefore, it imposed a number of stringent and exceptional pre-conditions to its approval that had to be carried out before drilling could commence and a drilling licence issued. This was necessary to secure additional levels of safety in the drilling operations.

Gulf's Request to shut in Surmont Gas (Decision 2000-22)

On April 3, 2000, the EUB issued its decision on a request by Gulf Canada Resources Limited (Gulf) that the Board order the shut in of associated gas production from 183 wells in the Surmont area. The Board concluded that continued production of associated gas at Surmont presents a significant risk to future bitumen recovery. Therefore, the Board approved Gulf's request in part, and will order the shut in of gas production from 146 wells specified in Decision Report 2000-22, effective May 1, 2000.

The Board carefully weighed the benefits and risks of allowing continued gas production to occur, versus the decision to order the gas production shut in. It was concluded that the bitumen resources on Gulf's Surmount oil sands leases represent a significant energy resource for the province that should be protected for future development. Reserves of natural gas in the requested shut in area are an important but far smaller energy resource. The Board recognized that as part of its conservation mandate, it would not serve the public interest to accept the possibility of jeopardizing a vast bitumen resource by allowing continued gas production to occur.

Subsequent to the release of the Decision Report, and pursuant to Section 91 of the Oil and Gas Act, the Province directed the EUB to prepare a compensation plan for those who may be harmed as a result of the wells being shut in.

The Public Utilities Board of Manitoba

Natural Gas

Natural Gas matters continue to be a major preoccupation of the Board with the result that about 10 major Orders were issued. Issues covered included the approval of franchise and expansion of service, rate increases and the acquisition of the privately owned gas distributor by the Crown owned Manitoba Hydro.

In considering franchise granting and expansion requests the Board dealt with a number of matters.

Of importance was the allocation of expansion costs to the various customer classes, the granting of franchise to whole areas, parts of which would never be served by the utility, the issue of allowing a rate surcharge to help finance capital costs of the projects and a request by citizens to order a plebiscite to determine the supplier of a property tax levy to finance the project under Section 66 of The *Public Utilities Board Act*.

The acquisition by a Crown Corporation of a shareholder utility raises a number of significant issues in the regulatory area. The purchase of Centra Gas consisted of an acquisition price of \$245M, plus Tax-transfer liability of \$78M payable to both federal and provincial governments (as the Company moves from private to Crown status) and \$15M short term obligations After the transaction the Provincial Government was paid \$29.5M and the Feds \$48.5M (i.e. the \$78M) as a one time payment. There were however annual taxes of \$4.4M to the Provincial Government and \$6.6M to the Feds. This has been left in the gas rates to pay down the \$78M. Once the debt has been retired, 37% of the \$11M will then go to Government as a grant in lieu of taxes and the balance will be used to pay down the accumulated interest after which all \$11M will go to the Government as a grant in lieu of taxes.

In its decision the Board noted the significant differences in the regulatory framework of each utility and the need to examine those frameworks. There were projected costs and benefits to customers and while savings resulting from the synergy of the amalgamation are projected to be about \$12M, the Board noted the risk to customers if the savings did not materialize. A number of recommendations and directives were provided to the utility. Specifically, the utility was required to:

1) submit, for Board approval, a functional integration plan including an annual monitoring process;
2) record all gas costs and revenues separate from electric costs and revenues for regulatory purposes;
3) record separately all direct acquisition costs for review by the Board on an annual basis;
4) record separately all direct integration costs for subsequent review by the Board;
5) record separately all cost savings directly related to the transaction for subsequent review by the Board;
6) within twelve months of the date of closing, report to the Board on the revised estimate of acquisition costs, integration costs, expected cost saving, and a proposed plan as to how the net benefits arising from the Transaction are to be shared between the customers of the gas and electric utilities;
7) make applications to the Board at the earliest possible date for confirmation of rates for the year 2000 for both the gas and electric utilities;
8) consider a shorter amortization period for all costs of the Transaction, including integration costs and goodwill;
9) not cross-subsidize the operations of one utility using the operations of the other utility;
10) consider the need for a new code of conduct which addresses how customer information and business transactions should be shared between the two utilities.

The Board also recommended to the Government of Manitoba that The *Public Utilities Board Act* be amended to remove Hydro's exemption under Section 2(5) which essentially eliminates the Board's jurisdiction under that Act, i.e., general supervisory powers.

Electricity

Supply reliability has become a significant issue for the U.S. marketplace and is impacting on all suppliers even those north of the U.S. border. The Board is examining its role in this regard and will likely have some regulatory responsibility. In the interest of harmonization, the Board will be reviewing with colleagues across the U.S. and Canada how this matter is best handled.

As noted earlier Centra Gas Manitoba Inc. was acquired by Manitoba Hydro, a crown corporation. They are currently regulated separately under two separate Acts. Manitoba Hydro is excluded from the jurisdiction of the Board pursuant to *The Public Utilities Board Act*. The Board derives its economic regulatory powers over Manitoba Hydro from *The Crown Corporations Act* which limits the Board's jurisdiction to approving rates only. The Board maintains jurisdiction over the revenue requirement of the utility but has no jurisdiction to approve or otherwise capital projects or to hear consumer complaints. The Board's general supervisory powers do not apply.

Centra Gas Manitoba Inc. continues to be regulated on a rate base rate of return methodology and this will not change in the immediate future. *The Public Utilities Board Act* with its broad powers applies in its entirety.

There is a view that this difference in regulatory oversight and powers will need to change. The question that needs to be answered is to what regime.

There are two paradigms and support can be given for both. Firstly, the paradigm supported by Manitoba Hydro which says, as a crown corporation the public interest issues associated with being a provider of an essential service in a monopoly environment are properly vested in the Government.

They would argue further that there is no conflict between the interests of the ratepayer and the corporate interests. They often refer to this as their "accountability wheel". They question the value the regulator brings particularly when costs are considered.

Further, their accountability is enhanced by the reviews of the Crown Corporations Council, an agency reporting to the Minister of Finance, by the convening of public accountability sessions, by meetings of the Public Utilities Committee of the legislature and of course, by customer complaints.

Others, including The Public Utilities Board argue that ownership issues should address the form of regulation but not the need for regulation itself. A regulatory referral still removes the complex issues of rate determination from the more pressing matters of the state at possibly no cost to Government. The regulatory process allows for an orderly process for such reviews and an ability for the public to influence those decisions on an informed basis.

Recognizing such entities have large capital requirements and if commissioned, can be of economic significance, legislatures are tempted to retain jurisdiction on such matters and perhaps, use a process to seek recommendations only. If the recommendations are not adopted does the risk of a financial disallowance remain if the regulator has jurisdiction over the revenue requirement and is such power useful?

Ontario Energy Board

Mandate

The *Energy Competition Act*, 1998 redefined the role and the mandate of the Board. While it granted some powers to the Board's previous role as a regulator of natural gas, it granted the Ontario Energy Board (OEB) substantial new powers in electricity.

Performance

Electricity Regulation - Market Opening November, 2000

Licensing & Codes

All electricity market participants must be licensed. All existing electricity distributors, transmitters and generators have been licensed with exception of 3 privately owned distribution companies. In 1999, seven retail licences were issued. Codes are a condition of licences. Six codes have been developed that will govern market participants:

The *Affiliate Relationships Code For Electricity Distributors and Transmitters* sets out the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies.

The *Electricity Retailer Code of Conduct* sets the minimum standards under which a licensed electricity retailer may retail electricity. Specific requirements may apply for offers made to residential or small business consumers.

The *DRAFT Transmission System Code* sets out the minimum conditions that a transmitter shall meet in managing its transmission system; the O&M standards; and the standard terms and conditions of a connection agreement.

The *DRAFT Distribution System Code* sets the minimum conditions that a distributor must meet in carrying out its obligations to distribute electricity.

The *Retail Settlement Code* sets the minimum obligations that a distributor and retailer must meet in determining the financial settlement costs of electricity retailers and consumers and in facilitating service transaction requests where a competitive retailer provides service to a consumer.

The *Standard Supply Service Code for Electricity Distributors* sets the minimum conditions that a distributor must meet in carrying out its obligation to sell electricity.

Rates & PBR

In order to separate "competitive" cost-of-power costs from monopoly wires charges, distribution utilities must develop unbundled rates. The Board developed a process and spreadsheet model to assist the distribution utilities to achieve this.

In January, 2000, the OEB approved a PBR plan for Ontario's 250+ distributors that adopts a price-cap for distribution rates, as well as minimum service quality performance standards and a consistent framework for service quality monitoring. The price-cap requires any change in distribution prices to be based on input-prices and a required annual productivity requirement. In addition, deferred return and prudently incurred transition/extraordinary event costs (outside the scope of the price cap) can be passed through to consumers. This performance-based approach decouples costs from revenues. The Board developed a process and handbook to assist the LDCs in implementing the approved PBR requirements in time for market opening. The *Electricity Distribution Rate Handbook* was released in March, 2000.

During the PBR proceeding, the Board provided distribution utilities with the ability to earn up to a market-based rate of return (up to 9.88%) on common equity.

The *Accounting Procedures Handbook*, including a *Uniform System of Accounts*, was also approved and issued in November, 1999. The Handbook provides guidance to electricity distribution utilities on accounting procedures and requirements as well as setting out a uniform accounting system.

One electricity rate proceeding was held in 1999 to establish transmission rates for Hydro One Networks Inc. (formerly Ontario Hydro Networks Company Inc.). Interim rate orders were issued for about 260 distributors. The Board also initiated a process to review the budget of and set fees for the Independent Electricity Market Operator (IMO).

Facilities Projects

To facilitate the Board's regulatory oversight of the monopoly "wires" systems in Ontario, work started on establishing means to assess the technical feasibility, economic consequences, and environmental significance of system expansions.

Mergers, Acquisitions, Amalgamations and Divestitures (MAADs)

In support of its regulatory oversight of MAADs in the Ontario electricity industry, the Board issued filing requirements guidelines in February, 2000. The Board's consideration of an application focuses on how the proposed transaction may impact on the achievement of the 6 objectives stipulated in the OEB Act, 1998.

Market Surveillance

In preparation for the Board's role in monitoring of markets in the electricity sector, a Memorandum of Understanding between the OEB, the IMO and the federal Competition Bureau is being drafted to clarify and coordinate roles and responsibilities.

Gas Regulation

Licensing & Codes

As of March 1, 1999, any individual or company selling natural gas to residential and small commercial consumers in Ontario must obtain a licence from the OEB. Twenty licences were issued in 1999. Gas marketers are required to adhere to;

An Affiliate Relationships Code for Gas Utilities which sets out the standards and conditions for the interaction between gas distributors, transmitters and storage companies and their respective affiliated companies.

The Code of Conduct for Gas Marketers which sets the minimum standards under which a gas marketer may sell or offer to sell gas to a low-volume consumer, or act as agent or broker with respect to the sale or offering for sale of gas.

Municipal Franchise Agreements

The Board undertook a review of revisions to the *Model Franchise Agreement* which was originally developed in 1987. A decision is expected this year.

Distributor Access Rule

The Board has convened an industry task force to make recommendations to the Board on rules that it should consider surrounding customer mobility, service unbundling, and how distributors should deal with retailers, customers, and consumers. The aim is to develop rules that are non-preferential and non-discriminatory, that maintain parity with developments in electricity, and that standardize business practices across gas distributors.

Rates & PBR

Both Enbridge and Union are moving towards the unbundling of their businesses and service offerings into the monopoly and competitive parts.

The Board approved a limited PBR plan for Enbridge Consumers Gas relating to operations and maintenance. Union Gas has submitted an application for rates based on a five-year PBR plan. A proceeding considering this application is currently underway.

Summary of Results

The Board worked closely with industry contemporaries to learn from their experience and to craft the new regulatory environment. Results include:

Policy, Rules & Regulations

- ✓ Accounting Procedures Handbook issued, and Uniform System of Accounts established
- ✓ Affiliate Relationships Code for Electricity Distributors and Transmitters issued
- ✓ Affiliate Relationships Code for Gas Distributors developed
- ✓ Customer Service Centre opened
- ✓ Distribution System Code developed
- ✓ Electricity Retailer Code of Conduct issued
- ✓ Electricity Distribution PBR introduced[1]
- ✓ Gas Distributor Access Rule developed
- ✓ MAADs Guidelines issued
- ✓ New Gas Model Municipal Franchise Agreement developed
- ✓ Retail Settlement Code issued
- ✓ Standard Supply Service Code issued
- ✓ Transmission System Code developed

Licences and Applications (Fiscal 1999-2000)

Electricity

263	Distribution Licences
11	Electricity Retail Licences
84	Generator Licences
3	Transmission Licences
4	MAADs
263	Interim distribution Rates Orders

Gas

72	Gas Franchise Agreements
19	Gas Marketer Licences
13	Facilities
12	Certificates
2	Rates

All OEB decisions and board orders are available on the OEB's website (www.oeb.gov.on.ca).

Preparing for Change

Strategic Alignment and Regulatory Process

A new committee structure has been adopted. An Executive Committee, sets and reviews the Board's business plans and activities, and recommends issues for Board consideration. A Management Committee, develops policies relating to, and oversees, the administrative aspects of the Board's operations. Four Technical Working Committees deal with matters in functional areas. These committees are charged with the responsibility to forward recommendations to the full Board regarding issues, policy and regulatory process. Board Member representatives on each of these committees also form a standing panel that can adjudicate on applications that do not require an oral hearing.

Focus on Communications and Customer Service

As electricity market opening approaches, consumer needs for current information about what is happening in the market and what choices are available to them are a priority. To advance consumer protection and education, the Board opened its new Customer Service Centre on March 20, 2000. The Centre provides information, in both official languages, to assist the public in understanding the evolving energy arena in Ontario. As well, the Customer Service Centre deals with

1 The rates implications aspects of the Board's decision on PBR as well as Standard Supply Service Code and the Retail Settlements Code, Distribution System Code, rates issues, wires-only distributioon activities, and other non-competitive electricity charges are assembled in the electricity Distribution Rate Handbook.

complaints and disputes between consumers and natural gas marketers or electricity retailers and refers unresolved complaints to a third party, complaint resolution contractor.

Stakeholder Consultation

Intensive stakeholder consultation and submissions to the Board resulted in the development and approval of industry codes and guidelines to govern participants in the market. The Board has been greatly assisted by industry task forces whose members met over several months to develop recommendations to form the foundation of performance-based regulatory schemes, utility accounting procedures, and draft codes, which were subject to broad public consultation prior to finalization. This participative approach to policy development and implementation continues.

Electronic Regulatory Filing

The Board is developing electronic regulatory filing processes and systems to achieve a more efficient regulatory process.

Cost Assessment and Recovery

A significant change to the Board's traditional cost assessment procedures was required during the year in recognition of its expanded responsibilities. New activity-based methods are employed to recover 100% of costs through fees, a general cost assessment and proceeding cost assessments.

Emerging Issues and Outlook

Issues that the Board will be wrestling with in the coming year include:

- Electricity Market Opening - How is the Board ensuring that its regulatory instruments and processes are ready for market opening?
- Consumer Information - How can the Board contribute to a smooth transition to a competitive electricity market?
- Review of Regulatory Process - How can the Board streamline information requirements and hearing processes?
- Retail Electricity Rate Setting - How might the OEB's responsibility with respect to retail electricity rate setting in Ontario evolve with emerging energy markets?
- Gas Utility Rate Regulation - How might the OEB's responsibility with respect to gas utility rate regulation in Ontario evolve with the shift PBR?
- Electricity Facilities Expansion - How might the OEB's obligation to review electricity system expansion proposals by the owners and operators of system facilities be implemented?
- Municipal Gas Franchises - What events may affect the way gas utilities interact with the municipalities they serve in the future?
- Market Surveillance at the OEB - How might the Board satisfy it's shared, legislated obligation to monitor electricity markets with the IMO?

In response to these issues, the Board anticipates an extremely busy agenda. Major activities include:

Regulatory Process

- ➔ Board Rules of Practice and Cost Assessment Guidelines
- ➔ Electronic Regulatory Filing Process and System
- ➔ Appeals Process

Audit / Investigations

- ➔ Confidentiality Guidelines
- ➔ Cost of Service Model
- ➔ Criteria for Conducting Audit Reviews, Investigations and Monitoring
- ➔ Filing Requirements for Board-wide Monitoring Needs

- Compliance Programs for Board Instruments
- Investigation procedures

Market Surveillance

- Market Surveillance Programs
- MAADs Applications

Electricity

- End-state Licences for electricity market participants, and Licensing Processes
- Rate Hearings: IMO Fees, Hydro One Networks Inc. Transmission Tariff (formerly Ontario Hydro Networks Company Inc.)
- Electricity Distribution Rate Unbundling and Re-balancing / Non-Competitive Charges (rate applications), 1st Generation PBR Review, and 2nd Generation PBR Policy
- Electricity Transmission and Distribution System Codes
- Standard Supply Service Implementation Guidelines
- Leave to Construct/System Expansion Requirements
- Facilities application

Gas

- Rate Hearings: Union Gas
- New Model Franchise Agreement
- Distributor Access Rule
- Facilities Applications

More Information

For more information on these and other matters that may be of interest to you, please contact:

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Régie de l’énergie du Québec

Introduction

The Régie de l’énergie is an arm’s-length, quasi-judicial economic regulation agency. The Régie is also a self-financing agency and it operates on the basis of the user-pay principle.

The Régie consists of seven permanent commissioners and one additional commissioner. The salaries and other labour conditions of its staff of 63 (full-time equivalents) are established by regulation and subject to government approval.

Electricity Sector

Determination of electric power transmission rates (R-3401-98)

The Régie decided to establish a two-phase process for the proceeding to determine the average unit transmission price and to modify transmission rates (held under the *Act respecting the Régie de l’énergie*, sections 48-51): first, an information phase consisting of at least three information sessions, which began in February 2000, and then the hearings per se, for which the first preparatory meeting was held on April 12, 2000. Hydro-Québec is to file its evidence in the summer of 2000.

Opinion on small private hydroelectric plants (R-3410-98)

At the Government’s request, the Régie submitted an opinion on December 14, 1999 (opinion A-99-02) on terms and conditions for the inclusion of power from small private hydroelectric plants in Hydro-Québec’s resource plan. Hearings were held from June 1 to 22, 1999 and 24 experts were heard. The Régie recommended that a set-aside of 150 MW be allocated to small private hydroelectric production and proposed that the price be determined through a competitive bidding process, with a price cap of 4.5 cents/kWh.

Hearing on Hydro-Québec’s terms and conditions of service (R-3439-2000)

On March 3, 2000, the Régie released a procedural decision (D-2000-35) concerning the framework for its review of some of Hydro-Québec’s terms and conditions for supplying electric power, the timetable for the hearings, and concerning some requests to intervene.

The Régie decided that the matters under consideration would be limited to the service contract and the related obligations, measurement and billing, terms of payment, and credit and collection policies. The Régie also established a timetable calling for a series of six technical meetings in June 2000 and the filing of Hydro-Québec’s proposal on August 14, 2000. The hearings are to be held in December 2000.

Natural Gas Sector

Application to modify GMCLP’s rates as of October 1, 1999 (R-3426-99)

In the decision D-2000-34, dated February 29, 2000, the Régie de l’énergie approved a 2.6% increase in transmission and distribution rates and the text of the resulting rates schedule. The increase is due to a major increase in TCPL’s rates and amortization of the rate stabilization account for unusual weather.

The authorized return on equity for distribution operations was set at 9.72%, based on an automatic adjustment mechanism established by the Régie in the 1999 rate proceeding. The Régie approved updated unit prices for 1B class "improved" interruptible service, on a temporary basis. The new rates are based on the most recent changes to cost allocation methods, including the redefinition of the "peak" factor. The Régie also authorized GMCLP’s application concerning terms and conditions for delivery service to the distributor’s service area, on a temporary basis.

Decision on Gazifère Inc.'s 1999-2000 rates application (R-3430-99)

In the decision D-2000-48, dated March 29, 2000, the Régie approved most elements of Gazifère's proposed formula for a multi-year incentive-based mechanism for determining the necessary operating costs Gazifère must bear in order to deliver service. This incentive-based approach is consistent with the objective of regulatory streamlining.

In the absence of a comprehensive cost allocation study, the Régie adopted a method for allocating administrative expenses to unregulated operations based on the proportion of revenues generated by those activities.

The Régie also approved, as part of a demand-side management plan, an energy efficiency program. The approved 10.13% rate of return on equity was set on the basis of the automatic adjustment mechanism approved in the preceding rate decision. The Régie authorized a 0.5% rate increase.

Decision D-2000-53 of March 30, 2000 concerning incentive-based measures or mechanisms to improve a gas distributor's performance and satisfy consumer needs (R-3425-99) and decision D-99-209, rendered on December 10, 1999

The Régie held public hearings in four phases:

Phase I: Procedural decision and determination of objectives, including the creation of a negotiated agreement process (NAP).

Phase II: Régie proposes guidelines for the NAP and topics for discussion.

Intervenors hold technical meetings, with the participation of Régie staff, followed by the signing of a unanimous report by participants (excluding Régie staff) on the guidelines, the topics and the timetable.

The report is enshrined in the Régie's decision D-99-209.

Phase III: Negotiations held from December 1999 to April 2000, leading to the filing of a negotiated agreement, with the Industrial Gas Users Association (IGUA) dissenting.

Hybrid agreement: revenue caps and price caps for five years, renewable by agreement, and a financing mechanism for energy efficiency programs.

Phase IV: A technical meeting attended by Régie staff and participants is held on June 27, followed by hearings in July.

Opinion for Government on the granting of exclusive distribution rights (R-3408-98)

At the Government's request, the Régie submitted opinion A-99-01 on September 3, 1999 concerning a request from Gaz Métropolitain and Company, Limited Partnership for exclusive distribution rights in the Lower St. Lawrence, Gaspé and North Shore regions. GMCLP plans to extend its network to serve industrial customers on the North Shore, with a possible linkup to the Sable Island development in Nova Scotia. The Régie's opinion was favourable to the application.

Petroleum Products Sector

Determination of gasoline and diesel fuel retailers' annual operating expenses (R-3438-2000)

In procedural decision D-2000-36, rendered on March 3, 2000, the Régie proposed to hold hearings on the renewal of decision D-99-133, which set operating expenses at 3 cents per litre. The Régie will not analyze the appropriateness of including an amount for operating expenses in the calculation of the minimum retail prices for gasoline and diesel fuel, since that analysis was performed for decision D-99-133.

Investigative report on fluctuations in the selling price of gasoline and diesel fuel between October 1998 and December 31, 1999 in the Abitibi-Témiscamingue, Saguenay/Lac Saint-Jean and Haute-Mauricie regions

In the fall of 1999, the Régie conducted an inquiry into fluctuations in the selling price of gasoline and diesel fuel in the Abitibi-Témiscamingue, Saguenay/Lac-Saint-Jean and Haute-Mauricie regions. The investigative report, released on February 24, 2000, is based on the information and data obtained in the course of the Régie's consultations with interested parties, including oil distributors (majors and independents) and local stakeholders in each of the regions. In general terms, the Régie concluded that the increases in gasoline and diesel fuel prices during the period under study were due primarily to international conditions over which Québec has no control. The investigation also showed that, despite some peculiarities, market forces were operative in the gasoline and diesel fuel markets in the regions in question.

Other Matters

Monitoring of distributors' operations

Subsection 31(2) of the *Act respecting the Régie de l'énergie*, which stipulates that the Régie has exclusive authority to monitor the operations of Hydro-Québec and of natural gas distributors in order to ensure sufficient supplies and fair rates for consumers, came into force on March 18, 1998. The Régie began monitoring Hydro-Québec's operations in the summer of 1998, initially focussing on the sufficiency of electric power supply. The Régie also asked distributors to file documents to assess their Y2K contingency plans.

Other

Amendments to the Act respecting the Régie de l'énergie: Bill 116

This bill amends the *Act respecting the Régie de l'énergie* in order to modify the board's jurisdiction as regards electric power rates, to introduce more competition into the electricity market, to make the board's mode of operation more flexible and to broaden its sources of funding.

The bill establishes the procedure for setting the rates and conditions applicable to the transmission and distribution of electric power. The costs to be taken into consideration by the Régie when setting the rates chargeable by the electric power distributor are treated differently according to whether or not the needs of Québec markets are being satisfied out of the heritage electricity pool. The annual heritage electricity pool is determined to correspond to a consumption of up to 165 terawatt-hours. The average cost of heritage pool electricity is set at 2.79 cents per kilowatt-hour and may be reduced by the Government.

The bill also provides that the cost of electric power other than heritage pool electricity will be determined by way of a tender solicitation governed by a procedure and a code of ethics submitted to the Régie's approval. Supply contracts will be awarded on the basis of the lowest tendered price and such other factors as the applicable transmission costs. Compliance with the tender solicitation procedure and code of ethics will be monitored by the Régie, and supply contracts entered into by the electric power distributor will require the prior approval of the Régie.

The determination of transmission rates and rates chargeable by the electric power distributor will be subject to a number of criteria, including uniformity throughout the territory served, and certain electric power transmission and distribution assets in operation or under construction are to be recognized for the purposes of rate setting. Moreover, the rates applicable to a class of consumers cannot be modified in order to alleviate the cross-subsidization of the rates charged by the electric power distributor.

Certain rules governing the operation of the Régie are to be altered, for instance as concerns the nature of the applications that may be examined and decided by a single commissioner. Moreover, the Régie will be authorized to hold conciliation sessions. The rules governing the financing of the Régie's activities are amended as are the provisions pertaining to the regulatory empowerment of the Régie and the Government.

Lastly, the bill contains technical amendments, amendments for concordance and transitional provisions.

Intervenors' Expenses

Decision on an Intervener Costs Payment Guide (R-3412-98)

In its decision D-99-124, rendered on July 22, 1999, the Régie approved an Intervenor Costs Payment Guide, following a generic hearing. The Régie adopted measures to optimize the use of resources so as to control the cost of regulation, measures related to interventions and the handling of applications, and measures to ensure more effective operations, including a requirement for all intervenors that want to claim reimbursement of their expenses to submit a preliminary budget and to use new claim forms.

Forum On Energy Regulation

The Régie organized a major Forum on Energy Regulation, together with the Canadian Association of Members of Public Utility Tribunals (CAMPUT) and the National Association of Regulatory Utility Commissioners (NARUC). The event drew nearly 1,000 participants from over 90 countries. Documents from the Forum are posted on the Web at http://www.energyforum.org.

The event helped CAMPUT raise its profile and expand its international relations, important components of its strategic vision.

The Régie thanks all the CAMPUT members who helped make the Forum an event of which we can all be proud.

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Board of Commissioners of Public Utilities of the Province of New Brunswick

The passage of the *Gas Distribution Act*, 1999 ("the Act") and the awarding of the general franchise for natural gas distribution to Enbridge Gas New Brunswick ("EGNB") by the Province has resulted in additional responsibilities and an increased workload for the Board. To meet these challenges, the Province appointed additional part-time commissioners last fall. Consequently, the current Board consists of a full-time Chairman with an open term and eight part-time commissioners serving either two year or three year terms.

In the past ten months, the Board has had an extremely busy calendar of regulatory activities relating to the marketing and distribution of natural gas. In November, the Board passed the following regulations:

i) *Gas Distribution and Marketers' Filing Regulation*;

ii) *Gas Pipeline Regulation*;

iii) *Gas Distribution Uniform Accounting Regulation*;

iv) *Gas Distribution Rules of Procedure*.

As the Act requires that gas marketers obtain a certificate from the Board before beginning to sell natural gas in New Brunswick, the Board considered that it would be appropriate to establish the rules that would apply to persons seeking a certificate and to the conduct of gas marketers operating in the Province. Rules were also required to govern the interaction between EGNB and gas marketers. The Board initiated a generic proceeding to deal with these gas marketers issues.

The gas marketers' proceeding was unique because it was the first time that the Board used a Consensus Committee approach. With this approach, parties hold meetings in an attempt to resolve issues prior to the public hearing. To assist the Consensus Committee, the Board appointed an independent facilitator to lead discussions. As the Consensus Committee was able to reach agreement on many items on the Issues List, the Board found the process extremely worthwhile in saving time and expense. Issues not resolved by this approach were dealt with in a hearing held in January.

The Board gave an Oral Decision on the gas marketers' issues in late January to facilitate market start-up and issued a written Decision in March. The Board decided that it will require all applicants for a marketer's certificate to complete a standard application form. Applicants are also required to provide a business plan and financial information to the Board in order for the Board to determine the necessity of the marketer providing a security arrangement. The Board also approved a Code of Conduct for gas marketers selling to low volume customers, established rules for EGNB governing its relationship to all gas marketers including affiliated companies and created an ongoing Working Group to consider emerging issues in the evolving natural gas industry in New Brunswick.

In February, the Board stayed a local producer franchise application by MariCo Oil & Gas Corporation.

Most recently, the Board held public hearings to consider two applications by EGNB:

i) A rate application setting distribution rates for Fiscal Year 2001,

ii) A permit to construct application for construction of EGNB's main grid distribution pipeline system in seven New Brunswick municipalities commencing in July of this year.

In May, the Board approved EGNB's market-based approach to set target distribution rates during the development period, i.e. the period during which EGNB cannot be expected to operate like a mature utility because it is still in the early stages of infrastructure development and customer capture. This market-based approach is premised upon the total delivered price of natural gas to the customer being below the equivalent price for fuel oil. EGNB proposed that its distribution rates be set so that the burner tip cost on an annual basis to the customer would be approximately:

30% below the fuel oil costs in the residential market;

15% below the fuel oil costs in the Light Fuel Oil markets;

5% below the fuel oil costs in the Heavy Fuel Oil market.

In approving this proposal, the Board recognized that there must be an incentive for customers to switch from their existing energy source to natural gas. While the Board approved the approach, it did not approve EGNB's target rates as filed because it became clear during the hearing, that the values for certain items in the target rate calculation may have changed significantly since EGNB prepared its proposed target rates. The Board directed EGNB to file proposed target rates that are based on current information together with supporting evidence to show how the value for each item was established. The Board anticipates dealing with EGNB's proposed target rate with a written submission process.

Decisions on EGNB's target rates, other outstanding issues from EGNB's rate application and EGNB's permit to construct application are pending. The Board will also issue a decision on the principles it will follow in considering intervenor cost awards under the Act in the nearfuture.

Prince Edward Island Regulatory and Appeals Commission

Tribunal Description and Mandate

The Prince Edward Island Regulatory and Appeals Commission – or "IRAC" as it is commonly referred to in Prince Edward Island was established in 1991 upon the amalgamation of the former Public Utilities Commission, Land Use Commission, and the office of the Director of Residential Rental Property. The Commission derives its legislative authority from the *Island Regulatory and Appeals Commission Act*. We believe the Commission's mandate is unique in that it is an independent tribunal having appellate, regulatory and administrative functions and responsibilities. There are numerous pieces of legislation which the Commission is called upon to administer in one way or another, but the main ones are: *Lands Protection Act*, *Petroleum Products Act*, *Maritime Electric Company Limited Regulation Act*. In addition, the Commission houses and funds the office of the Director of Residential Rental Property, or Rentalsman, created under the *Rental of Residential Property Act*. The Commission also has appellate responsibilities under the *Planning Act*, the *Unsightly Property Act*, the *Revenue Administration Act*, the *Real Property Assessment Act*, the *Real Property Tax Act*, the *Roads Act* and the *Heritage Places Protection Act*. IRAC operates at arms-length from the Provincial Government with two full-time Commissioners – a Chair and a Vice-Chair, together with six part-time Commissioners who are appointed by Lieutenant Governor in Council. The Commission is served by a staff of approximately 18. The work of the Commission is carried out by five main divisions: Administrative Services, Land, Office of the Director of Residential Rental Property, Petroleum and Technical Services – each having separate and distinct responsibilities.

Recent Significant Events/Emerging Issues

1. Provincial Solid Waste Management System:

The Provincial Government appointed Island Waste Management Corporation has continued to move forward with a province-wide waste management system which is based on recycling and composting. An initial recycling process is to be implemented in the greater Charlottetown area during the summer of 2000.

The Provincial Government's original plan was to establish a private sector, utility type operation to operate a province-wide solid waste management system. This approach would have, in turn, required a regulatory involvement of the Island Regulatory and Appeals Commission in establishing and monitoring service, as well as approving customer rate charges. With the Government appointed Waste Management Corporation, which will work as a non-profit operation while utilizing local firms for the waste management work, there is not, at this time, any move to provide for an independent regulatory process.

2. Natural Gas:

The Province, through its Provincial Energy Corporation, is still pursuing the extension of the natural gas transmission pipeline for Sable Island natural gas to Prince Edward Island. The main problems continue to be the cost of bringing natural gas to the Island and the potential economics of the market for natural gas within the Province.

The Province is attempting to ascertain the development (economic) potential on the Island for natural gas through a request for Expressions of Interest. Through this process, the Province is providing possibly interested developers an opportunity to describe the details of their proposed development plans, as well as the impacts that their plans would have on the Island's economy. Interested developers will also have to demonstrate their technical and financial abilities to implement their plans.

The Expression of Interest process is seen by the Provincial Government as the first stage of a process to fully assess the feasibility of constructing a natural gas pipeline to Prince Edward Island. This process also requires the interested developers to consider maximizing the amount of electricity generation on-Island using natural gas, providing a staged natural gas distribution plan and providing natural gas access for the Province's large industrial users. Developers have until April 28, 2000 to respond.

Again as noted last year in this forum, the Provincial Government at this time sees the natural gas sector as a business development process and has not identified any role for IRAC in the business development aspect or future regulatory requirements. In fact, the Province's *Natural Gas Distribution Act* provides for the establishment of a National Gas Distribution Board which would have broad powers to monitor and regulate natural gas usage in the Province. This Board has not yet been established.

3. Electricity:

Maritime Electric is a wholly-owned subsidiary of Fortis Inc. The Company operates under the provisions of the *Maritime Electric Company Limited Regulation Act*. The principles of this Act are:

An obligation to serve;

- A requirement to maintain a prescribed level of system reliability;
- A minimum of 40 percent common equity in the Company's capital structure;
- A monopoly to sell electricity on Prince Edward Island; and,
- Rates for electricity and ancillary services on Prince Edward Island to be no greater than 110 percent of NB Power rates for comparable service in New Brunswick.

IRAC's role under this Act is one of monitoring Maritime Electric's performance within the established principles. The application of the 110 percent rate principle has seen residential electric bills decrease by 12.4% between July 1994 and March 2000. However, in the Spring of this year, Maritime Electric increased its residential energy charge by 3 percent through the appliance of the 110 percent of NB Power rates, as those rates were increased in New Brunswick.

The increased move by regulators and the industry across North America to competitive models has not yet impacted the electric utility arrangement in Prince Edward Island. It is inevitable that this will happen at some point in the future and will require a fundamental rethinking of IRAC's and the electricity industry's roles in Prince Edward Island. The possible availability of natural gas may also see some changes in the operation of Maritime Electric and its relationship with IRAC.

4. Petroleum

The Province's *i* provides that IRAC approve prices for petroleum products within the Province. The volatile petroleum market conditions of mid and late winter brought substantial pressure on IRAC from the petroleum wholesalers to have IRAC move from a cost-driven approach starting with crude oil, to a market-driven approach related to rack prices for setting petroleum prices.

IRAC recognizes that the sharp peaks in wholesale prices for different petroleum products during the past winter season have been a test for its approach to establishing fair and reasonable pricing for petroleum products on the Island. As a result, a number of wholesalers have made application to IRAC requesting consideration of changes to the price-setting process. IRAC will be very careful in dealing with these requests in view of the fact that the existing process appears to have provided fair treatment over the years for both the sellers and consumers of petroleum products. While the volatile peaks of this past winter did generate some concern within the wholesalers, that level of volatility was somewhat unique when looked at from the longer perspective of IRAC's role in setting petroleum product prices.

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Nova Scotia Utility and Review Board

General

Charles J. McManus, P. Eng., a long-time member of the Board, passed away on November 4, 1999. His insight, experience and sense of humour are sorely missed by his colleagues at the Board. At the time of death he was president of CAMPUT.

In April, 2000, the Board assumed responsibility for the adjudicatory functions of the former *Nova Scotia Alcohol and Gaming Authority*. The Board's other adjudicatory functions include hearing assessment and planning appeals, compensation appeals under the *Victims' Rights and Services Act*, compensation claims under the *Expropriation Act* and conducting municipal boundary and school board electoral district boundary reviews. On the regulatory side, the Board regulates electric and water utilities and natural gas. It also regulates public passenger motor carriers and has certain regulatory responsibilities with respect to automobile insurance.

This report will be confined to electricity, water and natural gas.

Electricity

The largest electric utility by far in Nova Scotia is Nova Scotia Power Inc. (NSPI). Privatized in 1992, it distributes 95% of the power in Nova Scotia, the balance being provided by six small municipal utilities. It generates 97% of the power produced in Nova Scotia.

While there have not been any moves towards deregulation or re-regulation in the electric utility field in Nova Scotia as yet, the coming of natural gas to Nova Scotia has prompted NSPI to apply to introduce rate options designed to give its larger customers greater pricing choices and to preserve its existing sales base.

In May, 2000, the Board authorized NSPI to offer a load retention rate to customers who are considering an alternate energy supply source of at least 2,000 kVA. The customer's option to use a supply other than NSPI's must be both technically and economically feasible. The price and conditions offered under the rate are to be determined on a customer by customer basis. Before a customer may take service under the rate, NSPI must satisfy the Board that the revenue from the customer will be greater than the incremental cost to serve the customer and shall make a "significant positive contribution to fixed costs". The Board must approve the price and conditions of service for each customer who applies to take service under the rate. It is widely anticipated that a large pulp and paper mill which will have the ability to take natural gas from the Point Tupper lateral, expected to come into service this year, will be the first applicant for service under this rate.

In June, 2000, the Board approved a real time pricing rate for NSPI. It will be available to customers with loads of 2,000 kVA or greater. Customers will pay an energy charge consisting of the marginal energy cost of producing energy in the next hour together with a "fixed cost adder" designed to recover fixed costs. Fixed generation costs are assigned to on-peak hours and are recovered through the adders. The remaining fixed costs are assigned to all hours. As an example of the difference in fixed cost adders depending on the time of day, for the peak period between 7:00 am and 11:00 pm, for customers taking service at a transmission voltage of 138 kV or greater, the rate is 3.244 cents per kWh. The off-peak rate is 0.268 cents per kWh. There is no seasonal variation in the rates. It is hoped that the rate will prompt customers to shift production to the off-peak hours thereby improving NSPI's load factor.

Water

Perhaps the most interesting of the Board's recent water decisions involved an application by the Cape Breton Regional Municipality (CBRM) for approval of a new water rate structure to apply to the customers of the eight former water utilities which existed prior to the amalgamation of a number of municipalities to form the Cape Breton Regional Municipality. CBRM sought approval of rates for the next five years. At the end of that time, all customers would pay the same rates and get the same quality of water. It is to be noted that most of the eight water systems are not inter-connected and that they are located in different areas of what is a large municipality geographically. The costs of service for the different water systems vary. CBRM argued that in order to undertake the heavy financial costs of upgrading most of the water systems to a common level which would meet the Canadian Drinking Water Guidelines, it would be necessary to adopt a value-of-service approach. Rate increases for the different water systems would come into effect as water treatment facilities were completed over the five-year period. The Board accepted the proposed approach, but approved rates for the first two years only.

Natural Gas

The Board has been pre-occupied with natural gas issues over the last year. On November 16, 1999, the Board awarded a Province-wide natural gas franchise to Sempra Atlantic Gas Inc., a subsidiary of Sempra Energy, a Fortune 500 Company, whose distribution subsidiaries have the largest number of natural gas customers in North America. The Board's decision was confirmed by the Governor in Council on December 16, 1999. The other applicant for a province-wide distribution franchise was Maritimes NRG, a joint venture of Irving Oil and Westcoast Energy. The Board anticipates that construction of Sempra's distribution system in Nova Scotia will begin later this year. The first counties to be served are expected to be Pictou and Colchester, which are on the Maritimes and Northeast mainline.

The Board has spent a great deal of time in the last several months gearing up for the necessary inspection and certification duties involved in the construction and operation of Sempra's pipeline system. The *Nova Scotia Gas Distribution Act* requires that the sale of natural gas be unbundled from the transportation function, and the Board has just completed a hearing with respect to the conditions which will apply to the sale of gas in Nova Scotia by gas marketers. A decision is expected this summer. While the general terms of Sempra's rate plan were set at the initial franchise hearing, a further hearing will be held in the early fall to finalize Sempra's first rate schedule and its rules and regulations.

Board of Commissioners of Public Utilities for Newfoundland and Labrador

The Board is an independent quasi-judicial regulatory agency appointed by the Lieutenant Governor in Council and operates primarily under the authority of the *Public Utilities Act*, R.S.N., 1990. The Board is comprised by statute of three full-time Commissioners and up to six part-time Commissioners. The Board has a staff complement of ten, comprised of six administrative staff and four regulatory staff. The Board is fully funded by assessments upon industries regulated and receives no funding from the Provincial Government.

The Board administers the following Acts, or parts thereof:

- The *Electrical Power Control Act*,
- The *Public Utilities Acquisition of Land Act*,
- The *Automobile Insurance Act (part)*,
- The *Motor Carrier Act*,
- The *Motor Vehicle Transport Act of Canada*,
- The *Expropriations Act*, and
- The *Public Utilities Act*.

Electric Utilities

The two main electric utilities operating in the Province of Newfoundland and Labrador regulated by the Board are Newfoundland Power Inc., an investor-owned utility, and Newfoundland and Labrador Hydro Corporation, a crown corporation. The Board receives numerous reports on a regular basis from the utilities on their operations, and the Board uses these reports in its continued overseeing of the electric utility industry in the Province.

In addition to Board orders dealing with contributions in aid of construction, the approval of revisions to the system of accounts, the funding and amortization of an early retirement program of Newfoundland Power, revisions to the 1999 capital budgets of the utilities, annual rate changes resulting from the rate stabilization adjustment and the municipal tax adjustment, the Board issued orders dealing with the decommissioning of a small, old and deteriorated section of distribution line, and the future review of the revenue recognition policy of a utility. These orders were issued as a result of applications to the Board, and the subsequent review and determination that public hearings were not necessary.

Other matters were reviewed by means of public hearings that allowed the presentation and examination of evidence. These included:

Capital Expenditures

Newfoundland and Labrador Hydro, November 16, 1999 - P.U. 19 (1999-2000)

The application of Newfoundland and Labrador Hydro (Hydro) for approval of its 2000 Capital Budget, and for approval of leases over $5,000 for the calendar year, was heard by the Board on November 16, 1999. After hearing the evidence presented, the Board approved, in Order P.U. 19 (1999-2000), in addition to the leases presented, a total Capital Budget in the amount of $36,265,000. This figure was 4.9% less than the total approved Capital Budget for 1999.

Newfoundland Power Inc., November 19, 1999 - P.U. 18 (1999-2000)

The application for approval of the 2000 Capital Budget of Newfoundland Power Inc., as well as leases in excess of $5,000 for the calendar year, included an application for an amendment to the 1999 Capital Budget, an application for an order fixing and determining the average rate base for 1998, approving the forecasted average rate base for 1999, and approving the forecasted average rate base for 2000. Also included was the application for approval of a revised return on rate base calculated as a result of the approved automatic adjustment formula.

The application was heard on November 19, 1999. The total 2000 Capital Budget of $41,771,000 was approved by the Board. This represented an increase of 1.8% over the total 1999 approved Capital Budget.

Also approved were the rate base for 1998, $488,204,000, the forecasted rate base for 1999, $503,298,000, and the forecasted rate base for 2000, $512,693,000.

Rate Adjustment Using The Approved Automatic Adjustment Formula

Newfoundland Power Inc., November 19, 1999 - P.U. 20 (1999-2000)

The automatic adjustment formula, that was approved in Board Order P.U. 16 (1998-1999) and implemented for the first time in Order P.U. 36 (1998-1999), was used for the second time to set the rate of return on rate base, and therefore the rate for Newfoundland Power for the year 2000. The application was received by the Board as a part of the application for approval of the 2000 Capital Budget.

The use of an average of the long-term Canada bond yield rates for the last five business days of October 1999 and the first five business days of November 1999 resulted in a yield of 6.18%, compared to a yield of 5.75% for the same period of the previous year. When input into the approved formula, the resulting rate of return on equity was 9.59%, compared to 9.039% for the previous year. 9.59% was used to calculate a rate of return on rate base, as is directed by the *Public Utilities Act*, of 10.28%, within a range of 10.10%-10.46%. The resulting overall average increase in rates, ordered by P.U. 20 (1999-2000), of .7% became effective January 1, 2000.

Decommission Plant and Write Off Assets

Newfoundland and Labrador Hydro, February 3, 2000 - P.U. 26 (1999-2000) & P.U. 5 (2000-2001)

An application was received from Hydro on November 16, 1999 requesting the Board's approval and consent for the abandonment of the Roddickton woodchip fired thermal generating plant and the Roddickton diesel generating plant. After the Board requested that any interested parties make known their concerns, it received a request for intervener status from the Town of Roddickton. The Board decided to proceed with a public hearing, which took place on February 3, 2000 in Roddickton.

After hearing the evidence presented, the Board decided to sever the application into two components. It dealt with the issue of the woodchip fired thermal generating plant in Order P.U. 26 (1999-2000) and deferred the issue of the diesel generating plant until further evidence could be heard at the continuation of the hearing in St. John's on March 14, 2000.

Board Order P.U. 26 (1999-2000) authorized the abandonment by Hydro of the woodchip fired thermal plant, at Roddickton, and the write-off of the undepreciated value, approximately $17 million, of the assets that are no longer used and useful, with the exception of the 450 kW diesel engine that was used for emergency start up purposes.

Following continuation of the hearing on March 14, 2000, the Board, on May 12, 2000, issued Order P.U. 5 (2000-2001) authorizing the abandonment of the diesel plant and the write-off of the undepreciated value of the assets no longer used and useful. The order imposed four conditions on the utility as follows:

A) Hydro is to provide by November 1, 2000 an emergency power supply of 1,500 – 2,000 kWh.

B) Hydro is to decide the staffing requirements necessary to providing the emergency power on a timely basis.

C) Hydro is to report quarterly to the Board specific information with respect to outages on that portion of the distribution system which was serviced by the abandoned facilities.

D) Over the next three years, Hydro is to conduct a reliability study of the main transmission line servicing the Great Northern Peninsula where the abandoned facilities are located.

CIAC Review

The Board is responsible for the Contribution in Aid of Construction charges of Newfoundland Power Inc. and Newfoundland Hydro as they relate to the provision of line extensions on behalf of commercial and residential customers. The current CIAC Policy approved for use by the Board requires prior approval of all line extensions for seasonal, residential customers, as well as for any line extensions where the construction costs are estimated to exceed $25,000.

During the preceding fiscal year, the Board dealt with fifteen CIAC applications.

Part of the 1997 CIAC Policy required the utility to conduct a two-year review of CIACs calculated for General Service Customers, over 10 kW, to ensure that connected-load information, load factors and other inputs into the CIAC calculation accurately reflect the customer's data as represented at the time the original CIAC was calculated. If certain of the factors vary in excess of ± 20%, the CIAC must be recalculated with any excess payments refunded to the customer and any additional CIAC contributions charged. Board staff are currently auditing Newfoundland Power's 1999 two-year CIAC reviews.

Energy Policy Review

On August 31, 1998, the Government of Newfoundland and Labrador announced its intention to conduct an energy policy review in light of the profound changes in the North American electrical industry as a whole, and the proposed development of the potential of the Churchill River in the province of Newfoundland and Labrador.

In its 1998-99 Report, the Board indicated that a draft phase-one Report for this review would be available in June 1999. While the Board is aware that a report has been made, it has not, as yet, been publicly circulated. In order to provide input to the Energy Policy Review and to provide Government with insight into alternative electric utility rate setting and regulatory mechanisms, the Board will be presenting a paper providing a capsule summary of initiatives undertaken in other jurisdictions. This paper will cover various performance-based methods of regulation in competitive environments.

Motor Carrier

On October 1, 1998, the Board received an application from certain ambulance operators requesting that the Board fix and determine the level of compensation to be paid the operators by the Provincial Department of Health and Community Services for the provision of road ambulance services. The application was made pursuant to provisions of the *Motor Carrier Act*.

Following publication of notice of the application, the Board received an intervention from the Minister of Health and Community Services which raised a preliminary issue of the Board's jurisdiction to deal with the application.

Following a hearing, held November 18, 1999, The Board, on December 21, 1999, issued Board Order M.C. 1 (1999-2000) setting out the legislative provisions of the *Motor Carrier Act* and *Regulations*, and rendered its decision that the Board had jurisdiction to deal with the application as presented.

In an Extraordinary issue of the *Newfoundland Gazette*, published January 11, 2000, Newfoundland Regulation 4/2000 was published. The intent of this regulation was to amend the provisions of paragraph 28(e) of the *Motor Carrier Regulations* by excluding ambulance service rates from the prerogative of the Board, and implementing Section 28.1, requiring the Board to fix rates, as a term of the certificates issued to ambulance operators, at the level established by the Minister of Health and Community Services.

Expropriation

Pursuant to the *Expropriation Act*, the Board has been charged with responsibility for determining compensation payable to land owners whose property has been expropriated, or adversely affected as a result of expropriation of property by the City of St. John's or the Province. The Legislation provides that only the Minister, or the City of St. John's may refer a matter to the Board. The Board's method of operation, constitution and other powers while operating under the Act are as specified in the *Public Utilities Act*.

Since last reporting, the Board has had three matters referred to it under the Act. In all cases, the matter was referred by the Minister of Works, Services and Transportation. All matters involved the expropriation of property from an owner, or injurious affect on property, occasioned by changes in road infrastructure. A brief description and the disposition of these matters is as follows:

1. This matter involved the expropriation of certain property to facilitate extension to the Trans Canada Highway by construction of an East –West arterial road.

   Prior to the commencement of a hearing into the matter, the Board was notified that the parties had arrived at a negotiated settlement.

2. This matter involved a preliminary motion seeking the Board's interpretation of a provision of the Expropriation Act.

   Upon hearing the parties, the Board issued E. A. 1 (1999-2000) determining the matter in favour of the claimant. The order made no award of compensation as none had been requested on the preliminary matter. The issue of compensation has not been referred to the Board for determination.

3. This matter involved injurious affection to property giving rise to a reduction in business resulting from the re-alignment of certain road infrastructure which the property owner alleged limited access to his hotel business.

   Upon hearing the parties, the Board issued Board Order E.A. 1 (2000-2001) awarding the claimant $300,000 as compensation for detrimental affection.

Copies of all Orders can be accessed from the Board's website at www.pub.nf.ca.

The Board continues to liaise with Government on a number of matters regarding the Act which it feels require revision in order for the Board to discharge its functional responsibilities under the Expropriation Act in a reasonable fashion.

Automobile Insurance

The Board continues to exercise responsibility for the regulation of automobile insurance rates charged by companies operating in the province. During the 1997 year, the property and casualty industry was subjected to a review by a Select Committee of representatives of the House of Assembly. In March 1998, this Committee reported to the House with recommendations regarding changes to the regulation of the automobile insurance industry as it relates to rates and the Board's continued involvement therewith. At the time of this report, the Board is aware of limited progress towards implementation of the Select Committee's Report.

Organizational Structure Review

Following a comprehensive review of the Board's organizational structure, completed during 1999, the Board made certain changes in order to streamline processes. A management committee of one Board member and two Directors was struck to undertake certain administrative decision-making functions previously requiring Board involvement. Directors were also empowered to make certain decisions in their respective areas of responsibility. The Board also implemented a number of recommendations arising from an outside Consultant's review of internal control mechanisms. The Board feels that these initiatives will positively affect the Board's operations, and will allow for more timely decisions in respect to administrative issues.

Other Noteworthy Events

On the 15th day of September 1999, the Supreme Court of Canada rendered its decision with respect to the wrongful dismissal of a Commissioner of the Board. In February of 1990, the *Public Utilities Act of Newfoundland* was repealed and a new *Public Utilities Act* was proclaimed. Upon the repeal of the former *Public Utilities Act*, the positions of all of the Commissioners came to an end. It was then the prerogative of the Lieutenant-Governor in Council to reappoint the Commissioners. One of the Commissioners, Andrew Wells, was not so reappointed, and commenced an action for wrongful dismissal. The Supreme Court of Canada held that Mr. Wells had been dismissed from his employment as a Commissioner and was due an appropriate notice period, or payment in lieu of notice. Upholding the Newfoundland Court of Appeals' earlier decision, the Supreme Court of Canada awarded Mr. Wells compensation in lieu of his entitlement of two and one-half years' notice. This included all pension benefits that Mr. Wells would have been entitled to had he continued to service as a Commissioner for the additional two and one-half years.

In October 1999, the Board's Vice-Chair, Ms. Leslie Galway, resigned to assume duties as Executive Director of the Newfoundland Ocean Industries Association, an industry association whose mission is to promote development of Canada's East Coast hydrocarbon resources. Leslie was appointed as a Commissioner in March 1990 and Vice-Chair in 1995. The Board is pleased to welcome as its new Vice-Chair, Ms. Darlene Whalen. Darlene holds a Bachelor of Engineering degree and a Masters degree in Applied Science and Environmental Engineering from Memorial University of Newfoundland. Darlene was appointed as a part-time Commissioner to the Board in May 1997 and assumed her new duties as Vice-Chair on May 29, 2000.

National Energy Board

The first part of this summary provides an assessment of the important events and decisions of the National Energy Board ("NEB" or "Board") over the last twelve months. The second part outlines emerging issues in the context of the Board's business plans and priorities for the next three years.

Significant Decisions

Many events and the NEB's key regulatory decisions of the 1999-2000 period highlight the national scope of the Board.

In northern Canada, oil and gas activity is accelerating. Following successful discoveries in the Fort Liard area of the Northwest Territories, the Board heard and approved an application by Shiha Energy Transmission Ltd. to construct a pipeline from a facility near Fort Liard to the Maxhamish Gas Plant in northeastern B.C., and eventually into Westcoast Energy Inc. The Board also approved a pipeline project from Ranger Oil Ltd. and Chevron Canada Resources that connects the Fort Liard ares to the Westcoast system at Pointed Mountain. In addition, the Ikhil project is now flowing gas to Inuvik from a nearby field, reflecting some local use of resources.

In Western Canada, the Board examined access by natural gas liquids (NGL) shippers to Canadian pipeline systems. In 1997, the Board directed Enbridge Pipelines Inc. (Enbridge), then called Interprovincial Pipe Line Inc., to develop a toll methodology application for facilities that would provide open access service for NGL shippers on the Enbridge pipeline. In March 1999, Enbridge filed an application for approval of a stand-alone tolling methodology for NGL storage and injection facilities. In October 1999, the Board held a technical conference to allow parties an opportunity to discuss issues related to the transportation of NGL on the Enbridge pipeline system. Following the conference, the Board directed Enbridge to conduct an open season for its proposal. As a result of a lack of industry support during the open season, the Board dismissed Enbridge's application in March 2000.

In early 2000, the Board held a hearing on an application from TransCanada PipeLines Ltd. (TransCanada) on proposed amendments to its interruptible transportation (IT) and short-term firm transportation (STFT) toll schedules. The proposal was to allow TransCanada the discretion to vary the floor prices for these short-term services, within a specified range, in response to changing market conditions. The Board denied TransCanada's request for pricing discretion but directed that the existing floor level for IT bids be raised from 50 to 80 percent of the applicable firm transportation toll effective 1 May 2000. The floor level for STFT bids was maintained at 100 percent of the applicable firm transportation toll.

In late 1999 Souris Valley Pipeline Ltd. completed construction of the first commodity pipeline approved by the Board. The pipeline will carry carbon dioxide from North Dakota to the Weyburn oil field near Goodwater, Saskatchewan, extending the life of the existing oil field by an estimated 25 years.

In central Canada, the Board approved an application by Vector Pipeline Limited Partnership (Vector) to construct and operate a natural gas pipeline in southwestern Ontario. The Vector project is part of a new international pipeline project to provide hub-to-hub service between Joliet, near Chicago, Illinois and Dawn, Ontario.

In eastern Canada, the Maritimes and Northeast Pipeline (M&NP) was opened for service in December 1999. The Board also heard and approved two applications from M&NP to construct natural gas lateral pipelines that will connect Halifax, Nova Scotia and Saint John, New Brunswick to the M&NP mainline.

Emerging Issues

The Board's purpose is to "promote safety, environmental protection, and economic efficiency in the Canadian public interest while respecting individual rights and within the mandate set by Parliament in the regulation of pipelines, energy development, and trade." In fulfilling this purpose the Board aspires to be a respected leader in safety, environmental protection, and economic regulation.

To meet these challenges, the Board has set four overriding goals. These are expressed as 'an end state.' Their importance and the strategies the Board has to realize them is discussed below.

Goal 1: NEB regulated facilities are safe and perceived to be safe

Pipelines in Canada carry hazardous materials that can pose a danger to the public and the environment. However, this danger can be effectively managed through competent design, construction, and maintenance practices.

Over the past eight years, the number of incidents (reportable events as defined in the regulations) has remained in the 70 to 90 range, despite recent changes in definitions which increased reportability. What is more important in terms of safety is that the number of ruptures (that is, those incidents which pose a significant threat to the public or the environment) has declined. In 1994, there were six ruptures while only one rupture occurred in each of 1998 and 1999.

To enable the industry to rationally address the risks associated to their system, the Board has moved towards goal-oriented regulations. The *Onshore Pipeline Regulations*, 1999 (OPR 99) is the first set of goal-oriented regulations under the Board's mandate. Environmental and Quality Management Systems, such as ISO 14000, or other similar systems, are the central ingredient in the OPR 99 and other regulations under development.

Goal 2: NEB regulated facilities are built and operated in a manner that protects the environment and respects individual rights

Many aspects of the NEB's regulatory role affect the protection of the environment and individual rights. The Board believes that effective environmental assessment and management systems are an integral part of managing safety and protection of the environment.

Other objectives are to ensure the maintenance or enhancement of high respect for public rights, to facilitate participation in Board processes, and to see that pipeline companies take increasing responsibility for landowner consultation.

Over the past year, the Board conducted two pilots where pre-hearing completion of comprehensive study reports was delegated to the proponent. The Board continues to seek ways to enhance clarity and consistency in environmental assessment while also emphasizing the role for proponents to plan and manage critical front-end assessment. In addition, the Board continues to conduct inspections and audits to ensure that companies are complying with regulations, undertakings, and application approval conditions.

Goal 3: Canadians derive the benefits of economic efficiency

The Board's objective in this goal is to ensure, to the extent that it influences economic outcomes, that Canadians derive the benefits of economic efficiency. There are three aspects of economic efficiency related to the Board's mandate.

The Board influences the operation of the industry through the decisions it makes. The Board seeks to promote a low-cost transportation network, to ensure that transportation services meet shippers' and consumers' needs and to promote rational investment decisions. For years, the Board has followed a policy of "letting markets work wherever possible." The Board believes that new participants in gas transmission are introducing a degree of competition into the industry that will be healthy in the long run, but acknowledges that it is posing some serious challenges to incumbent pipelines in the near term.

Expansions of the TransCanada and Foothills systems in the fall of 1998 largely eliminated the phenomenon of "trapped " gas in Alberta. The construction of the Alliance Pipeline and approval of the Vector project initiated a fundamental change by providing competition to the TransCanada system. These events are bringing new challenges for existing companies. For example, the non-renewal of some long-term transportation contracts on the TransCanada system has resulted in increased pipeline tolls. Changing market and business realities in the industry are leading the Board to examine more flexible approaches.

The Board can also impose costs on industry if its regulatory processes are unnecessarily cumbersome or delay economically beneficial projects with no offsetting gains in public protection. One measure of improving regulatory efficiency is the cycle time for application processing. While facilities applications vary greatly in complexity, the average cycle time for processing non-hearing applications has improved over the past year. Last year, Board staff examined the non-hearing application process and identified several areas where this process could be streamlined. This project is in its early stages and communication and consultation with stakeholders is planned in the near future.

As an independent neutral source of market energy information, the Board can provide information and analysis to industry participants which may assist in decision making. In 1999, the Board published its long-term outlook, Canadian Energy - Supply and Demand to 2025 and an Energy Market Assessment entitled Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin, 1998-2001.

Goal 4: NEB meets the evolving needs of the public to engage in NEB matters

This goal is an all encompassing goal in that engagement of the public is vital to ensure all information critical to a decision has been heard. Also, communication is critical in promoting the goals of safety, environmental protection, and economic efficiency. Easy access to information is one key aspect that will be facilitated greatly by the Electronic Regulatory Filing project, being jointly implemented with the Ontario Energy Board. Further, the Board's efforts and decisions need to be fair and seen to be fair. Thus, success in this goal is necessary to be truly successful in the other three goals.