NEWFOUNDLAND AND LABRADOR
BEFORE THE
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF the Public Utilities Act, (R.S.N. 1990, Chapter P-47 (the "Act")),

AND

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for approvals of: (1) Under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to its Retail Customers, Newfoundland Power, its Rural Customers and its Industrial Customers; (2) Under Section 71 of the Act, Its Rules and Regulations applicable to the supply of electricity to its Rural Customers; (3) Under Section 71 of the Act, the contracts setting out the terms and conditions applicable to the supply of electricity to its Industrial Customers; and (4) Under Section 41 of the Act, its 2002 Capital Budget.

Pre-filed Evidence

of

Dr. John W. Wilson

July 31, 2001

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DIRECT EVIDENCE OF

DR. JOHN W. WILSON

I. QUALIFICATIONS AND INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 1601 North Kent Street, Suite 1104, Arlington, Virginia, 22209.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a B.S. degree with senior honors and a Masters Degree in Economics from the University of Wisconsin. I have also received a Ph.D. in Economics from Cornell University. My major fields of study were industrial organization and public regulation of business, and my doctoral dissertation was a study of utility pricing and regulation.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE THAT TIME?

A. After completing my graduate education I was an assistant professor of economics at the United States Military Academy, West Point, New York. In that capacity, I taught courses in both economics and government. While at West Point, I also served as an economic consultant to the Antitrust Division of the United States Department of Justice.

After leaving West Point, I was employed by the Federal Power Commission, first as a staff economist and then as Chief of FPC's Division of Economic Studies. In that capacity, I was involved in regulatory matters involving most phases of FPC regulation of electric utilities and the natural gas industry. Since 1973 I have been employed as an economic consultant by various clients, including federal, state, provincial and local governments, private enterprise and nonprofit organizations. This work has pertained to a wide range of issues concerning public utility regulation, insurance rate regulation, antitrust matters and economic and financial analysis. In 1975 I formed J.W. Wilson & Associates, Inc., a Washington, D.C. corporation.

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have authored a variety of articles and monographs, including a number of studies dealing with utility regulation and economic policy. I have consulted on regulatory, financial and competitive market matters with the Federal Communications Commission, the National Academy of Sciences, the Ford Foundation, the National Regulatory Research Institute, the Electric Power Research Institute, the U.S. Department of Justice Antitrust Division, the Federal Trade Commission Bureau of Competition, the Commerce Department, the Department of the Interior, the Department of Energy, the Small Business Administration, the Department of Defense, the Tennessee Valley Authority, the Federal Energy Administration, and numerous state and provincial agencies and legislative bodies in the United States and Canada. In Canada I have undertaken assignments on behalf of B.C. Hydro, Ontario Hydro, municipal utilities, the Federal Government and this Board.

Previously, I was a member of the Economics Committee of the U.S. Water Resources Council, the FPC Coordinating Representative for the Task Force on Future Financial Requirements for the National Power Survey, the Advisory Committee to the National Association of Insurance Commissioners (NAIC) Task Force on Profitability and Investment Income, and the NAIC's Advisory Committee on Nuclear Risks.

In addition, I have testified on numerous occasions as an expert on financial, competitive and regulatory issues, and I have participated as a speaker, panelist, or moderator in many professional conferences and programs dealing with business regulation, financial issues, economic policy and antitrust matters. I have been retained by this Board on two previous occasions. In 1996 I pre-filed evidence and testified on cost allocation and rate design matters in conjunction with Newfoundland Light and Power Company's rate application, and in 1997 I provided the Board with a Report concerning Newfoundland Power Company's Study of Innovative Approaches to Rate Design Based on Marginal Costs and Time-of-Use Design Principles. I am a member of the American Economic Association and an associate member of the American Bar Association and the ABA's Antitrust, Insurance and Regulatory Law Sections.

Q. WHAT IS THE PURPOSE OF YOUR PRE-FILED EVIDENCE IN THIS PROCEEDING?

A. I have been asked by the Board of Commissioners of Public Utilities of Newfoundland and Labrador ("the Board") to prepare a Report assessing Newfoundland and Labrador Hydro's ("Hydro") Application and pre-filed evidence concerning cost-of-service methodology, rate design and proposed rates. That Report is incorporated in my pre-filed evidence and is provided as an attachment to this testimony.

Q. PLEASE SUMMARIZE YOUR REPORT.

A. The Report first provides an overview of cost-of-service and rate design principles and then discusses the specific issues that I recommend for particular attention in this proceeding. These issues are:

- The assignment of network transmission costs (including substations) to demand (rather than energy) and the allocation of these costs using a single C.P.

- The assignment of no distribution system costs to energy and the allocation of all non-customer distribution system costs in proportion to the system coincident peak.

- The absence of seasonal or time-of-use differences in rate design.

- Hydro's proposed energy-only rate for NP (without time-of-use or seasonal price variations).

- The absence of marginal cost considerations in Hydro's cost allocation and rate design proposals.

- The use of a "zero intercept" method to assign distribution system costs to the "customer" classification.

- The extent to which Hydro's proposed rates reduce the rural deficit (except for Government rates).

Additional issues that I have noted for consideration include:

- The extent to which the RSP may disconnect price signals from cost causation.

- The reasonableness of Hydro's proposed reduction of non-firm industrial demand charges.

- The classification of gas turbine and diesel fuel to demand.

- Using system load factors to classify NUG purchases between demand and energy, while assigning all industrial purchases to energy.

The Report concludes with several specific recommendations.

Q. WHAT ARE THOSE RECOMMENDATIONS?

A. Based on my review of Hydro's proposed cost-of-service methodology and rate design, I offer the following recommendations:

- Hydro should prepare and file rates reflecting seasonal cost variations. A utility with a winter demand double its summer demand, that allocates all of its demand costs between customers on the basis of winter peak demand, should have seasonally differentiated rates.

- Marginal cost considerations should receive greater attention in designing rates. This can be accomplished within a fully distributed, embedded cost context and need not adhere to "pure" marginal costs theories. In addition to facilitating the cost-reflective design of seasonal rates, consideration of marginal costs may warrant time-of-use rate differentials, facilitate the specification of cost-effective interruptible service discounts and eliminate pricing differences between classes and customer categories that do not reflect cost differences.

- Hydro should propose cost-reflective rates for NP that charge separately for each classified cost category (e.g., demand, energy) and that vary between seasons and time-of-use in line with costs. This is an important step that is required in order for NP to develop retail rates for its own customers that accurately reflect both actual resource costs and the charges that will accrue to NP as its loads change over time.

- Hydro should classify all of its transmission network costs between demand and energy. This can be done in proportion to system load factor or in accordance with marginal cost principles.

- Distribution network costs should be classified principally to energy and demand, and distribution demand costs should be allocated in proportion to non-coincident demand measures. Distribution networks are designed to meet local load requirements. Other than customer specific costs (e.g., meters, service drops), the customer costs of a distribution network are best measured for rate design purposes as the cost savings to a utility if a customer leaves the system.

- The Board should consider developing an evidentiary record regarding the extent to which the rural deficit should be reduced and the extent to which universal service should be subsidized. Hydro should continue to cover the rural deficit based on equity considerations that the Board deems appropriate. One equitable way to cover the rural deficit without distorting price signals would be to fund it through marginal cost rate design methods.

- If the Board chooses to implement rate design principles that reflect costs, consideration should be given to eliminating the RSP component that intentionally defers cost recovery to future time periods.

Q. DOES THIS, TOGETHER WITH THE ATTACHED REPORT, CONCLUDE YOUR PRE-FILED DIRECT EVIDENCE AT THIS TIME?

A. Yes; it does.

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Report to

The Board of Commissioners

of Public Utilities

# of Newfoundland and Labrador

by

J. W. Wilson & Associates. Inc.

July 31, 2001

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EXECUTIVE SUMMARY

This Report assesses the pre-filed evidence submitted in this matter by Newfoundland and Labrador Hydro (“Hydro”) in support of its Application as it relates to cost of service methodology and rate design issues. The Board of Commissioners of Public Utilities of Newfoundland and Labrador (“the Board”) has requested this Report assessing Hydro’s Application and pre-filed evidence concerning cost of service methodology, rate design, proposed rates, changes in rules and regulations and impacts on customer classes. In addition to reviewing Hydro’s Application and pre-filed evidence, we have also reviewed the Board’s 1993 Report on Cost of Service Methodology and the generic methodology outlined therein. Our review of Hydro’s cost allocations and proposed rate design also includes the proposed method of recovering Hydro’s rural subsidy.

The class cost of service study submitted by Hydro in this proceeding and summarized in Hydro’s pre-filed evidence generally follows traditional cost of service principles and substantially complies with the generic cost of service methodology outlined in the Board’s February, 1993 Report. However, improvements are feasible for several cost of service classifications and allocations and for rate design elements. The Board may also wish to consider some matters further in light of changes that have occurred during the past eight years. Several potentially important supporting documents and other material were not submitted with the Application and should be provided for the Board’s review in this proceeding. Most notably, this includes the distribution study supporting Hydro's proposed continued use of the "zero intercept" method for classifying distribution plant costs.

Substantive cost allocation and rate design topics that we believe merit particular consideration by the Board in this proceeding include the following:

- The assignment of network transmission costs (including substations) to demand (rather than energy) and the allocation of these costs using a single C.P.

- The assignment of no distribution system costs to energy and the allocation of all non-customer distribution system costs in proportion to the system coincident peak.

- The absence of seasonal or time-of-use differences in rate design.

- Hydro's proposed energy-only rate for NP (without time-of-use or seasonal price variations).

- The absence of marginal cost considerations in Hydro's cost allocation and rate design proposals.

- The use of a "zero intercept" method to assign distribution system costs to the "customer" classification.

- The extent to which Hydro's proposed rates reduce the rural deficit (except for Government rates).

Additional issues for consideration include:

- The extent to which the RSP may disconnect price signals from cost causation.

- The reasonableness of Hydro's proposed reduction of non-firm industrial demand charges.

- The classification of gas turbine and diesel fuel to demand.

- Using system load factors to classify NUG purchases between demand and energy, while assigning all industrial purchases to energy.

Based on our review of Hydro's proposed cost of service methodology and rate design, we offer the following recommendations:

- Hydro should prepare and file rates reflecting seasonal cost variations.

- Marginal cost considerations should receive greater attention in designing rates. This can be accomplished within a fully distributed, embedded cost context and need not adhere to "pure" marginal costs theories.

- Hydro should propose cost-reflective rates for NP that charge separately for each classified cost category (e.g., demand, energy) and that vary between seasons and time-of-use in line with costs.

- Hydro should classify all of its transmission network costs between demand and energy.

- Distribution network costs should be classified principally to energy and demand, and distribution demand costs should be allocated in proportion to non-coincident demand measures.

- The Board should consider developing an evidentiary record on the extent to which the rural deficit should be reduced and the extent to which universal service should be subsidized, giving consideration to funding the rural deficit through marginal cost rate design.

- If the Board chooses to implement rate design principles that reflect costs, consideration should be given to eliminating the RSP component that defers cost recovery to future time periods.

I. INTRODUCTION

This Report assesses the pre-filed evidence submitted in this matter by Newfoundland and Labrador Hydro ("Hydro") in support of its Application as it relates to cost of service methodology and rate design issues. The Board of Commissioners of Public Utilities of Newfoundland and Labrador ("the Board") has requested this Report assessing Hydro's Application and pre-filed evidence concerning cost of service methodology, rate design, proposed rates, changes in rules and regulations and impacts on customer classes. In addition to reviewing Hydro's Application and pre-filed evidence we have also reviewed the Board's 1993 Report on Cost of Service Methodology and the generic methodology outlined therein. Our review of Hydro's cost allocations and proposed rate design also includes the proposed method of recovering Hydro's rural subsidy.

It is our conclusion that the class cost of service study submitted by Hydro in this proceeding and summarized in the pre-filed evidence of Hydro's cost of service witness, John A. Brickhill, generally follows traditional cost of service principles and substantially complies with the generic cost of service methodology outlined in the Board's February, 1993 Report. There are, however, several ways in which rate design improvements can be made as well as a number of matters that the Board may wish to consider further in light of changes that have occurred during the past eight years. We also note that several potentially important items underpinning Hydro's pre-filed evidence were not submitted with the Application and should be provided for the Board's review in this proceeding. These include (1) the Distribution Study and updates prepared for Hydro by Foster Associates and described by Hydro's witness Brickhill at pages 2-5 of his pre-filed testimony, (2) Hydro's loss of load hours ("LOLH") study supporting the 2CP generation demand allocator as referenced at page 8 of Mr. Brickhill's pre-filed evidence, and (3) Hydro's study of the practicality of attributing energy losses to rate classes on a time differentiated basis as noted at page 9 of Mr. Brickhill's pre-filed evidence.

Substantive cost allocation and rate design topics that we believe merit particular consideration by the Board in this proceeding include the following:

- The assignment of network transmission costs (including substations) to demand (rather than energy) and the allocation of these costs using a single C.P.

- The assignment of no distribution system costs to energy and the allocation of all non-customer distribution system costs in proportion to the system coincident peak.

- The absence of seasonal or time-of-use differences in rate design.

- Hydro's proposed energy-only rate for NP (without time-of-use or seasonal price variations).

- The absence of marginal cost considerations in Hydro's cost allocation and rate design proposals.

- The use of a "zero intercept" method to assign distribution system costs to the "customer" classification.

- The extent to which Hydro's proposed rates reduce the rural deficit (except for Government rates).

Additional issues for consideration include:

- The extent to which the RSP may disconnect price signals from cost causation.

- The reasonableness of Hydro's proposed reduction of non-firm industrial demand charges.

- The classification of gas turbine and diesel fuel to demand.

- Using system load factors to classify NUG purchases between demand and energy, while assigning all industrial purchases to energy.

This Report is organized to first provide an overview of cost of service and rate design principles with attention to how they relate to this proceeding. Following this overview, we discuss each of the specific issues noted above.

II. COST ALLOCATION AND RATE DESIGN PRINCIPLES

The traditional process for establishing a set of electric utility rates involves five steps:

(a) Establishment of the total revenue requirement, or rate level, required by the utility.

(b) Grouping of the customers into classes upon which different rates will be imposed.

(c) Division of the total revenue requirement into the revenue responsibilities for each class. This is usually done by functionalizing, classifying and allocating the utility's rate base and operating costs.

(d) Design of the general rate form to be used to collect the appropriate revenue from each class.

(e) Specification of the detailed elements of each rate, in accord with the overall rate design, class revenue responsibilities, and test year quantities of service actually furnished by the utility.

Although the revenue requirement or rate level is often the issue that is most hotly contested in electric utility rate proceedings, it is not the subject of this Report, which, instead, focuses on cost allocation and rate structure issues.

As noted in the pre-filed evidence of Hydro witness Paul R. Hamilton, the objectives of utility rate structure have been recognized for many years. Professor James C. Bonbright provided a useful and comprehensive enumeration of these objectives in his well-known 1961 text, <u>Principles of Public Utility Rates</u>. Bonbright identified the three primary criteria of a desirable rate structure as follows:

1. Providing the required revenues;

2. The "fair-cost-apportionment objective"; and

3. The optimum-use or consumer rationing objective."

The fair cost apportionment objective (as well as the total revenue requirement objective) is mandated under law in many regulatory jurisdictions. In Newfoundland and Labrador, this principle of horizontal equity is set forth in the <u>Public Utilities Act</u> which requires that "all tolls rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons at the same rate" (Section 73(1) of the <u>Public Utilities Act</u>, R.S.N. 1990).

In addition, Bonbright identified several other criteria that are not necessarily subsumed by the three primary criteria. They are:

1. "The related 'practical' attributes of simplicity, understandability, public acceptability, and feasibility of application."

2. "Freedom from controversies as to proper interpretation".

3. "Revenue stability from year-to-year."

4. "Stability in the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers."

These additional criteria, although important, are generally assigned less weight in evaluating a rate structure than the "three primary criteria."

The substance of these objectives has not changed over the ensuing four decades, although the emphasis placed on the primary objectives has increased significantly. Most notably, beginning in the late 1970s with the passage of the Public Utilities Regulatory Policies Act in the U.S. and corresponding initiatives at the provincial level in Canada, the complimentary goals of <u>conservation</u>, <u>efficiency</u> and <u>equity</u> emerged as the hallmark of modern electric utility rate design. An economically sound cost-of-service study is a critical precondition to the achievement of these goals.

Cost-of-Service Study

The primary purpose of conducting a cost-of-service study is to create a useful guide for setting rates. The most important use of a cost-of-service study is to determine the cost responsibility of each customer class, which can then be used as a guide to determine the revenue responsibilities of each class. The study assigns a portion of the utility's rate base and operating expenses to each customer class. The full cost of serving each class can then be determined by allocating a portion of the total return to each class; this is achieved by applying the allowed jurisdictional rate of return to the rate base allocated to each class. This cost-of-service figure can then be used as a guide in determining the rates the utility may charge to earn those revenues that should be recovered from each rate class consistent with its class cost responsibilities.

The first step in a class cost-of-service study is functionalization. Typically, three major "functions" are defined – power production, transmission, and distribution. The first of these functions, power production, or simply production, includes all aspects of generation, e.g., the cost of production plant itself, fuel expenses, purchased power expenses, and any other expenses related to the production of electric power. The second function, transmission, includes the cost of transmitting energy from sources of the bulk power supply to load centers, and integrating these supplies to meet network load requirements. The third function, distribution, includes all the costs associated with distributing electric energy from the transmission network to individual customers at usable voltage levels.

Every expense the utility incurs must be assigned to one of these functions. In some instances, the basis for the assignment is obvious. For example, it is clear that fuel costs should be assigned to the power production function. In other cases, the proper assignment is less obvious. For example, it is less readily apparent to which of the functions administrative and general expenses and common plant should be assigned.

It may be appropriate to divide these three major functional areas into finer categories. For example, transmission service may be divided into subtransmission and bulk transmission, although the dividing line between these categories is likely to be imprecise and thus subject to debate. The distribution function is frequently divided into primary and secondary distribution, with various customers being served at primary and secondary voltages. This separation of distribution costs permits greater refinement when analyzing cost causation. For example, customers who take service at primary voltages, and make no demand on the secondary system, would then bear only the costs related to the construction and operation of the primary distribution system.

The burdens that an individual customer or customer class places on the power production, transmission or distribution systems are not easily measured. Consequently, a further step is required to assign the functionalized costs to dimensions of electric service which subsequently will be attributed to individual customers or to customer classes. This initial refinement of cost responsibility is referred to as the classification of costs. There are three major cost classifications – an energy-related component, a demand-related component, and a customer-related component. For example, power production costs can be divided between the cost incurred to produce energy and the cost incurred to meet demand. This is true for transmission, too. For distribution plant, costs can be divided among the costs incurred to meet maximum demands, the costs incurred to meet energy requirements, and the costs that must be incurred simply to ensure that each customer has access to the system.

After costs have been "functionalized" and "classified" they are ready to be "allocated" to customer classes. In theory, the process of allocating the functionalized and classified costs is straightforward; one simply allocates each category of cost to whichever classes caused the utility to incur those costs. On most utility systems, the two largest customer classes are residential service, which is for individual households, and general service, which is for most non-residential customers. On many electric utility systems, the general service category is broken into several major business service categories, divided either between commercial and industrial customers, or according to the size of the load. Likewise, the residential class may be subdivided into space heating and non-space heating customers or in some other manner related to size of load or end use. In addition, there are often smaller service classes such as street and area lighting. With few exceptions, all customers are metered for energy consumption and all energy-related costs should be allocated into classes in proportion to their energy usage.

Classifying and allocating demand- and customer-related costs is a more complicated, and, typically, contentious proposition. There are numerous alternative demand classification and allocation procedures, each with its own rationale, and some of these alternative methods produce significantly different class cost responsibilities. Deciding upon which among the available alternatives is most appropriate for the utility in question is one of the major controversial issues in performing cost-of-service studies.

The most common controversies surrounding the proper classification and allocation of costs concern the classification of (1) production and transmission costs between demand- and energy-related components, and (2) distribution facilities costs between customer-, energy-, and demand-related components. Cost classification procedures that assign more costs to “demand” than to “energy” favour high load factor customers (e.g., industrials) and result in higher charges to low load factor customers (e.g., residentials). Likewise, cost classification methods that attribute more costs to “customer” and less to “demand” or “energy” generally result in lower bills for big customers and higher bills for small customers. Not surprisingly, perceptions of cost allocation equity often differ between customer groups in concert with these predictable end results.

Investments and expenses should be classified according to the purpose for which the investment and/or expense has been made. Importantly, in this regard, the installation and operation of generation and transmission plant depends on the utility’s entire load pattern, and not just the level of peak demand that must be met.

If a utility’s goal for power plants was simply to meet peak demand, rather than building expensive base load capacity, it would install less costly local peaker plants with much lower generation and transmission network capital requirements. Peakers and their associated transmission facilities have much lower capacity costs but are more expensive to run. But, if they only run during peak times, the higher running costs are justified in order to save on capital costs. Much more costly, but operationally efficient (i.e., low operating costs) baseload generating plants are installed, if they can be run long enough to generate enough fuel savings that more than offset their higher capital expenditures. Hence, these higher capital costs are incurred to serve year-round energy requirements at lower total costs.

These same principles are true for capital intensive, high voltage transmission grids that deliver power from generating plants and tie their output together in an integrated network. Baseload plants and their associated transmission grids are used to deliver and assemble energy practically around-the-clock, and a significant portion of their relatively high capital costs are justified by long hours of use (i.e., an energy consideration) and not predominately by a limited peak hour demand.

A potential area for disagreement with Hydro's assignment of costs in this proceeding relates to these classification issues. Owing to the high initial cost, large hydroelectric generating plants are not economical unless they can be run a sufficient number of hours in the year for the savings from their low running cost, as compared to the cost of the oil or other fossil fuels required for less expensive generators, to more than offset their higher initial (or capital) cost. Higher capital cost hydroelectric plants should therefore be built only to meet the "base loads" that persist around the clock and throughout the year, even in slack times.

If the constraining resource on a stored hydroelectric system is the amount of water that is available in the year, then it may be the case that nearly the same amount of capacity investment will be required regardless of the seasonal or time-of-use distribution of the utility's load. For example, if large amounts of water become available for storage in the early summer when it rains and in the spring when snow melts, it may be the case that nearly the same storage capacity will be required whether the water is released evenly throughout the year or unevenly in response to widely varying seasonal loads. In that case, the capital cost of storage capacity is virtually all energy-related and should be allocated and recovered in proportion to energy consumption rather than in proportion to peak demand or even the system's load factor.

When a plant serves both baseload and peak needs, its classification should reflect both functions. The Board has recognized this functional duality of hydroelectric units, and has found it appropriate to classify a significant portion of generation and transmission plant fixed expenses as energy-related. These costs should be recovered from all energy users.

<u>Rate Design</u>

Customers are grouped into different classes so that they may be charged different rates. These rate differences are generally intended to reflect differences in the cost of furnishing service, but sometimes they reflect end use differences that are not correlated with cost differences. In general, after customers (or "ratepayers") are grouped into several classes, each class purchases its electricity service from a different rate schedule. Each electric rate schedule, or tariff, is a price list for electricity service.

The development of a rate schedule requires the selection of the numerical values for the specific rate elements. These elements must be chosen in such a way that the rates recover the authorized total revenue requirement or, if class revenue responsibilities have been determined, the authorized responsibilities for each class. This is accomplished by reference to the billing determinants for the so-called test year. The billing determinants are the quantities for each kind of service provided and billed by the utility, such as kilowatt-hours of usage in each rate block, kilowatts of demand, and number of customers. The test year is the twelve-month period to which the revenue requirements determination is applicable, and the billing determinants for the test year are the quantities of service against which the authorized revenue is to be recovered.

Rate design requires the establishment of the general principles according to which a specific rate is constructed. For example, the choice between a one-part rate (as Hydro proposes here for its sales to NP), which has only an energy (kilowatt-hour) charge, and a two-part rate, which has both demand (kilowatt) and energy charges, is an issue in rate design. So is the choice between a declining block rate and a flat rate, an annual rate and seasonal rates, and so forth. Rate design questions are typically addressed with specific reference to the utility's cost structure as developed in the class cost of service study. Rates for each class of customers are set at levels that are intended to recover that portion of the utility company's costs that is apportioned or allocated to the class.

The rates must be calculated so that, when applied to the test year billing determinants, they provide precisely the authorized revenue for that test year.

Selection of the specific rate elements that meet this requirement, and that are constructed in accord with the accepted rate design principles, completes the process of constructing authorized rates. Hydro's proposed design is in general conformance with these principles. However, Hydro is somewhat unique in that one wholesale customer, Newfoundland Power ("NP"), is responsible for more than 60 percent of Hydro's total system load and energy sales and more than 70% of its Island Integrated System's load and sales. Hydro's rates for NP, in turn, account for a large portion of NP's cost of service and the rates that it must charge to retail customers in Newfoundland. These matters are discussed, below.

III. HYDRO'S PROPOSED COST ALLOCATION AND RATES

Hydro's Classification of Transmission Costs

Hydro's cost allocation and rate proposals reflect significant recognition of the cost classification principles described above as they relate to generation plant costs, but less so for transmission plant investments. Utilities typically use transmission for two purposes: to reduce generating costs and to mitigate the need to add resources. Transmission facilities reduce the cost of kWh output by integrating generation resources. A cost-minimizing utility maintains a mix of generating resources in order to meet the varying demands placed on its system. This mix allows the utility to reduce overall production costs, thus lowering the cost of energy. In order to be successful at this, the utility uses its transmission grid to achieve optimal dispatch. Hence, the transmission grid helps reduce energy costs and this should be recognized in the classification of transmission costs. This causality is not adequately recognized in Hydro's classification of transmission costs, which attributes virtually all grid costs (i.e., with the exception of lines used exclusively to connect remote generation) to peak demand.

If a generation plant is located near the source of fuel, rather than near the load center, the cost of fuel is reduced, but transmission costs are increased. The extreme example of this is a hydroelectric plant that must be located at a water source, and the power generated there must be transmitted over high-voltage transmission to load centers and integrated on a transmission network with power production from other locations. The result is a savings on energy-related generating costs at the expense of greater transmission costs. In Hydro's case, substantial transmission investment and expense is clearly related to both the transport and network integration of less costly energy from remote locations rather than to simply meet peak demand. The important network integration aspect of these facilities would be better recognized by using load factors to assign a portion of all transmission plant to energy.

<u>Hydro's Allocation of Distribution Demand Costs</u>

A related issue is Hydro's proposal to allocate all non-customer distribution system costs on the basis of coincident peak demand. The coincident peak method basically allocates all costs classified as demand-related to customer classes in proportion to each class' contribution to the system coincident peak or peaks. The rationale for this approach is that the required capacity is determined by the maximum coincident demand to be placed on the system. However, this rationale does not hold where the cost level is not determined by system coincident peak demand. In the case of local distribution networks, it is local loads, which often vary from the system coincident peak, that determine plant requirements. Therefore, a noncoincident demand allocator for distribution capacity is generally thought to be more reasonable for cost allocation.

Since each class may experience its own peak at a different time than that at which the system peak occurs, the sum of the non-coincident class peaks typically will exceed the system coincident peak by a significant margin. This inter-class diversity benefits the system in the sense that the utility need only install sufficient generation capacity to meet the diversified (i.e., coincident) peaks of the several classes. But this is not equally true with respect to distribution plant requirements. A non-coincident peak demand allocation method assigns demand-related costs to customer classes in proportion to each class' share of the sum of all class non-coincident peaks ("NCP"). Thus, in contrast to the coincident peak method, this procedure distributes the interclass diversity benefits generated by the off-peak consumption characteristics of customers in any given class. Compared to the coincident peak approach, classes which have peaks coincident with the system would be assigned a smaller share of total NCP demand-related costs, and classes with high diversity would be assigned a larger portion of these costs.

Although the use of NCPs in determining a class' responsibility for demand-related generation and transmission investments may be questionable, the use of NCPs to allocate demand-related distribution costs is more reasonable. Demand-related distribution facilities are typically installed to meet each local areas' loads, rather than demands at the time of the system coincident peak. However, class contributions to these local loads are not generally measured with precision, and therefore some available proxy must be used. It is typically argued that non-coincident class peaks are a better proxy for the true cost-causative factor in this setting, because portions of the distribution system are frequently built to serve only customers in a single customer class (e.g., a distribution system for a new residential development). Sometimes the sum of the individual customer non-coincident maximum (billing) demands is used as the proxy for demands placed on local distribution systems, and demand-related distribution costs and investments are allocated on the basis of a class' share of these demands. Neither is an ideal proxy for the class contributions to local area peak demands, but either is likely to be preferable to using class contributions to the system coincident peak for purposes of allocating distribution demand costs.

Seasonal and Other Time-of-Use Cost Variations

Hydro's proposed rates have no summer-winter differential, and Hydro has presented no evidence reflecting its marginal costs or seasonal cost variations. This is especially noteworthy in that (1) Hydro's winter peak loads have historically been about double its summer peaks, and (2) Hydro allocates virtually all of its demand costs between classes in proportion to winter peak loads. Seasonal rate variations would be a reasonable expectation with Hydro's winter peak so prominent, both in terms of dramatic seasonal demand variations and in terms of Hydro's own proposed cost allocation procedures.

As noted above, if the constraining resource on a stored hydroelectric generating system is the amount of water that is available in the year, then it may be the case that nearly the same amount of capacity investment will be required regardless of the seasonal or time-of-use distribution of the utility's load. In that case, the capital cost of storage capacity is virtually all energy-related and should not be allocated or recovered in proportion to peak demand. Thus, the dominance of stored hydroelectric capacity in the relevant generating mix can justify a smaller winter-summer rate differential than the seasonal load curves themselves would suggest. Nevertheless, given Hydro's extensive seasonal demand diversity and its allocation of all generation demand costs on the basis of winter peak, there should be significant seasonal rate variations.

In short, in order for Hydro's rates to reasonably reflect costs, seasonal cost variations should be reflected. Conversely, if it is argued that the dominance of stored hydro generation overrides justification of seasonal rate differentials, then the attribution of hydroelectric capacity costs to demand and the allocation of these costs based on winter peak is inappropriate.

NP's Energy-Only Rate

One of the most important rate design considerations before the Board in this case is whether Hydro should continue to price NP's wholesale power requirements on the basis of an energy-only rate. Mr. Osmond indicates, at page 9, that, pursuant to the Board's direction, NP and Hydro have reviewed the implementation of a demand and energy pricing structure and have concurred that the energy only rate "remains appropriate." The testimony is unencumbered by any information concerning the nature of their review or the factors that influenced their conclusion.

NP is Hydro's largest customer, accounting for more than 70% of total load and sales in the Island Interconnected System and more than 60% of all of Hydro's sales and load throughout Newfoundland and Labrador. The rates that are charged to NP, therefore, account for a large portion of Hydro's total revenue requirement, and NP also bears a large part of the rural subsidy. All of these charges are, in turn, passed on to NP's own retail customers. Relatedly, the lack of seasonal variation in rates that Hydro charges to NP is reflected in NP's retail rate policy which, likewise, imposes no seasonal price variation.

In the past, NP has attempted to design its own retail rates by looking behind the energy-only rate that it pays to Hydro so as to attempt to reflect a perception of what its sees as Hydro's cost structure in its own retail charges. In this process, a large portion of Hydro's energy-only wholesale charges are reattributed to demand by NP in allocating its own retail revenue requirement. There are two fundamental problems with this procedure: first, NP's incremental or marginal revenues from its own customers are likely to be substantially different than its payment obligations to Hydro; second, the Board is faced with the very difficult task of attempting to tie retail rate design to underlying costs in a proceeding where the cost of service study is not the Applicants' work product and therefore not subject to comprehensive evaluation or simultaneous consideration with retail rate design.

It would be far better, and a more reasonable regulatory procedure, to calibrate Hydro's costs and wholesale rate structure in this proceeding so that retail rate design in the next NP rate case can reflect the appropriate cost-based charges that NP will actually realize as its retail sales volumes change.

Marginal Cost Pricing

In addition to ignoring seasonal cost variation in its rate design, Hydro's pre-filed evidence does not embrace or address marginal cost pricing principles. While this is consistent with the Board's 1993 recommendation "that Hydro's Cost of Service Study be of the embedded type," the Board has given further consideration to marginal cost pricing principles since that time. Moreover, it is increasingly clear that rates which reflect marginal cost responsibility are more allocatively efficient and better embody the principles of fairness, equity and causal responsibility for cost incurrence than rates that diverge from marginal costs.

Designing rates that assign revenue responsibilities to customers on the basis of their marginal costs of service provides two important results. First, it leads to an equitable distribution of system costs among customers. This is the generally accepted economic definition of equity – that is, customers should be charged according to the costs they impose on the system.[1] Second, this approach to ratemaking provides the users of electric power with price signals that reflect the true costs to the utility and to society of providing them with that power. This is especially important in a market economy, because it leads consumers to use more of those resources that are relatively plentiful and less of those that are

[1] There are other definitions of "equity" that have more to do with redistributing costs among customer groups according to some subjective criterion. This is sometimes referred to as "social ratemaking," and a "life-line" rate structure is the usual product of this ratemaking approach. Thus, time-of-use rates clearly constitute a continuation of the historical approach to equity in ratemaking as opposed to "social ratemaking."

relatively scarce. Economists refer to this most important common sense result of proper pricing as “allocative” or “production efficiency.”

When a utility charges rates below cost to one customer class and rates above cost to another, electricity prices will diverge from the cost of providing service and distort allocative efficiency. Economic or allocative efficiency means going as far as possible in the satisfaction of wants within the existing resource and technological constraints. In a market economy this is achieved by pricing products (like electricity) that use scarce resources (e.g., labor, capital and fuel) to reflect the resource costs of producing them. On the consumer’s side, this principle means that consumption should be curtailed when the value of electricity consumption is less than the resource cost to society of producing electric power. From the utility’s standpoint, economic efficiency means that the appropriate mix of capital and other resources should be employed in the most efficient manner to minimize the total costs of producing the quantity of electric power that consumers freely determine they desire at the prevailing price level. Economic efficiency goals will be defeated if costs are allocated in a manner that ignores cost causation.

Marginal cost ratemaking does not change the traditional method of determining a utility company’s total revenue requirement, but it does alter all the other steps in the process for setting rates. The important ways in which marginal cost ratemaking adds to or changes the traditional process of determining rates are as follows:

- The structure of electric utility costs is analyzed with much greater reference to the time of electricity use than is found in a traditional class cost of service study.

- The structure of electric utility costs is analyzed, at least in large part, in terms of the change in total costs (or the incremental cost) associated with a unit of service rather than the average cost per unit in a traditional class cost of service study.

- The elements in the rate design correspond more directly to the service functions (e.g., demand, energy, etc.) used in developing the cost study, so that the numerical value assigned to each rate element equals the marginal cost found to be associated with that element in the cost of service study (except to the extent that deviations are required so that total revenues are equal to total costs).

- Marginal cost pricing generally leads to the imposition of essentially the same rate schedule on all customers in all classes with variations only for actual cost differences such as voltage levels or time of use.[2]

- To extent that metering costs or other institutional restraints prevent the imposition of a single set of cost-based rates for all customers on the system, and instead force the grouping of customers into classes, the assignment of class revenue responsibilities should reflect marginal cost principles.

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[2] Note that this is not the likely result when marginal cost rates are adjusted to conform with class revenue requirements that were determined based on cost functionalizations that are unrelated to marginal costs. For example, it may be well and good to estimate the marginal costs of demand based on the estimated capital cost of a combustion turbine peaker. But if the marginal cost price is then adjusted to conform with a class revenue requirement that reflects the much greater unit capital costs of hydroelectric dams as the demand component of costs, all that was good and well before adjustment may be undone. The reasons for functionalizing a substantial portion of hydroelectric dam costs as energy-related are essentially the same as those for estimating the marginal costs of demand based on the capital cost of a CT peaker, and the same logic should guide both rate design and cost allocation methods.

Customer Costs: The Zero Intercept Method

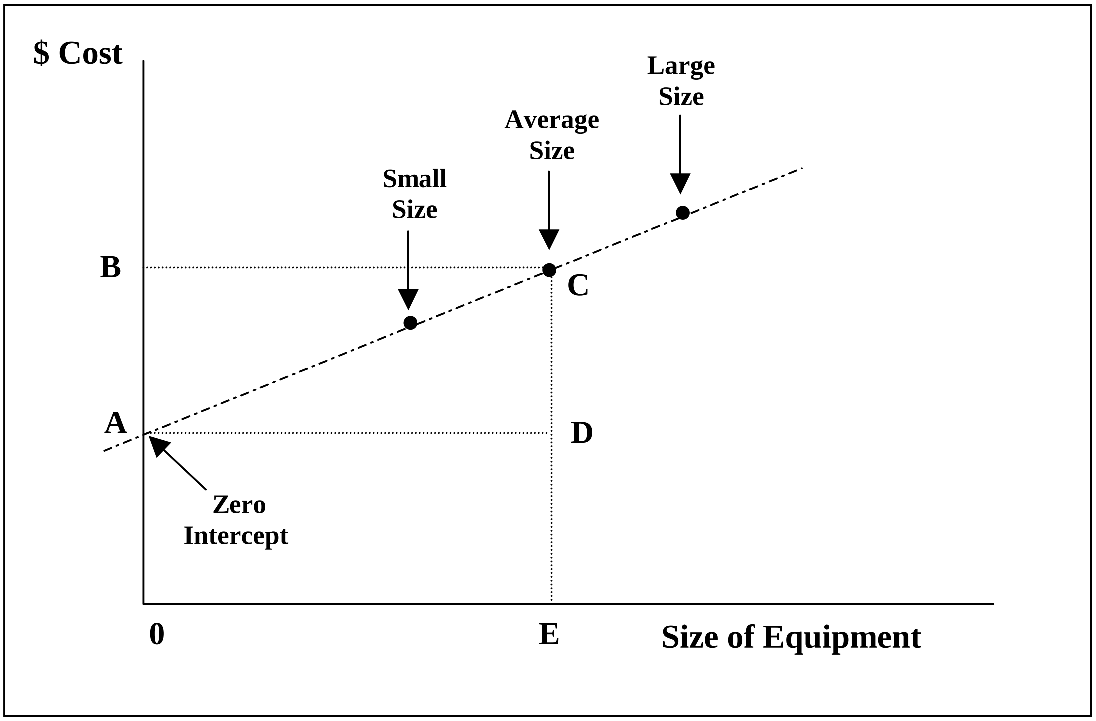
The customer component of distribution facility costs is supposed to reflect the costs that are incurred to connect customers to the system, whether they actually consume any power or not. This amount is allocated to classes on the basis of the number and type of customers in each class. This division is accomplished by determining the customer-related component of facility costs. These customer-related costs are directly assigned to the customer function. These include costs such as metering and billing. For the most part, the assignment of these costs as customer-related is fairly straightforward and non-controversial.

A more controversial assignment of customer-related costs deals with an estimate of some theoretical minimum or “zero intercept” system. This approach attempts to ascertain the minimum or “zero intercept” system based on engineering or statistical studies. Such a theoretical minimum system would consist of the smallest poles, lines and transformers that would connect a customer to the system, but without regard to the demand that customers would impose on the capacity of the equipment.

In its 1993 Report, the Board considered Hydro’s “zero intercept” methodology and accepted it for interim use. The Board concluded, however, that the method did not have wide regulatory acceptance (see the concurring opinion by Bonbright, quoted below) and stated that, "it is reluctant to recommend [a] methodology for long term use which is logically inconsistent." The Board went on to recommend that Hydro prepare a revised study of distribution cost for presentation to the Board in its next rate referral.

Hydro again uses a "zero intercept" method in this case to divide distribution system costs between the customer and demand classifications.[3] Essentially, this involves plotting the various sizes of equipment on a graph with cost on the vertical axis and size on the horizontal axis, and extending a trend line through the various sizes of equipment with various costs until it intersects with the vertical (or cost axis). That point of intersection is the "zero intercept" and the cost level of the zero intercept is assumed to reflect the cost of the equipment (e.g., pole, transformer, conduit, etc.) that is not load related. That portion of the cost (0ADE on the graph below) is classified as customer cost and the remainder (ABCD) is classified as demand cost.

[3] The regression analyses that comprise the zero-intercept analysis have not been included in Mr. Brickhill's testimony. Mr. Brickhill, at pages 2-4, notes that the second method of splitting distribution into its demand and customer components is the minimum system study and that a minimum system study was not attempted because the Hydro data is "inadequate" to perform a reliable study. Neither the nature of the requisite data nor the deficiencies in Hydro's data base are identified.



There are two issues with this approach to cost classification. First, as in all minimum size system methods that use actual load-bearing equipment to identify minimum cost (or, as here, "zero intercept") the minimum actual equipment size is not the same as the theoretical zero load size. Second, even if the method could be structured to correctly identify the cost of a minimum zero load facility, there would still be no valid basis to attribute all of the difference between actual cost and zero load cost entirely to coincident peak demand and none of these costs to energy.

Aside from the esoteric engineering or statistical considerations involved with ascertaining good estimates of this zero size system, there is a more fundamental flaw with the minimum system approach to assigning customer costs.

A minimum or zero load size methodology ignores the basic fact that the costs associated with investments in distribution lines and related equipment are part of an integrated power delivery network; they are not customer-specific facilities that are causally attributable on the basis of customer counts. This is because a utility's distribution facilities costs have been sized and installed to meet the expected loads placed upon them, and not to meet either a range or a specific number of customers to be served. It therefore makes little sense to allocate the costs of distribution plant on the basis of the number of customers being served in each rate class.

The following hypothetical example illustrates the fact that an electric utility's distribution lines, poles and transformers are sized and installed to meet customer loads and not customer counts:

> An area of a specific size may contain 20 individual commercial customers, each with a 50 KW peak load, or 4 office buildings, each with a 250 KW peak load, or 5 apartment buildings, each with 40 individually metered apartments having a 5 KW peak load. While the number and type of service connection and meters will vary directly with the number of customers, the local distribution facilities must be structured to handle a 1,000 KW peak load in each case, regardless of whether there are 4 or 20 or 200 customers.

> The point of this illustration becomes even more obvious if one assumes that the 4 office buildings, each with 250 KW of peak load, are converted to 40 individually metered apartments with each customer having 5 KW of peak load. With this conversion, metering and accounting costs may change, but essentially all other elements of the distribution system (e.g., poles, and overhead and underground lines) will remain the same, even though the number of customers increases 10 fold!

Thus, as Bonbright, *et al.* have observed:

> The really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitively earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) distribution system – a fraction equal to the estimated annual costs of the hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage while keeping them from falling of their own weight. In any case, the annual costs of this phantom, minimum-size distribution system are treated as customer costs and are deducted from the annual costs of the existing system…. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the length of the distribution lines depending on the type of the distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero intercept" method whereby regression equations are run relating cost to

> various sizes of equipment and eventually solving for the cost of the zero-sized system.
>
> What this last-named cost computation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis (D. Lessels, *Public Utilities Fortnightly*, December 4, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the Company's entire service area stays fixed, an increase in the number of customers does not necessarily betoken any increase whatever in the minimum-size distribution system (James C. Bonbright, Albert L. Danielson, and David R. Kamerschen, Principles of Public Utility Rates, Public Utility Reports, Inc.: Arlington, Virginia, 1988).

The consequence of the failure of the minimum-size or zero intercept methodology to provide a reliable basis for classifying customer-related costs is that the customer-related component of distribution facilities should largely be limited to clearly identifiable, directly assigned costs like accounting and billing, meters, and service line drops.

Rural Deficit

As the Board correctly observed in its 1993 Report, "the allocation of the rural deficit represents the allocation of another group of customers' cost of service." While there may be more or less equitable ways of allocating this cost subsidy among Hydro's other customers, there is no single allocation method for these costs that is superior from an economic efficiency viewpoint or that will attribute these costs in accordance with cost causality principles.

In the Board's 1992 proceeding, Hydro proposed to allocate the rural deficit between subsidizing classes in proportion to each ones' total revenue requirement before the subsidy allocation (i.e., in accordance with dollars of revenue). In response, NP argued that a revenue-based deficit allocation would be unfair because Labrador customers with low rates would bear a smaller share of the burden. NP proposed to allocate the deficit on the basis of 50% energy and 50% revenue requirement. The Board agreed that charging certain classes with higher subsidy costs simply because they had higher rates to start with seemed unfair, and consequently recommended an allocation approach proposed by the Board's expert (Mr. Baker) which first prorated the deficit between allocated demand, energy and customer costs and then allocated these prorated deficit amounts to each class in proportion to class demand (KW), energy (MWh) and customer totals. Hydro has followed this Board-recommended approach in its present Application, except that, in accordance with the 1996 Legislative Amendment to the Electrical Power Control Act ("EPCA"), which stated that "after December 31, 1999 industrial customers shall not be required to subsidize the cost of power provided to rural customers in the Province," no deficit allocation has been made to Hydro's industrial customers.[4]

While Hydro's treatment of the rural subsidy allocation is therefore consistent with the Board's 1993 equity-based recommendation and the 1996 Legislative Amendment to EPCA, this filing makes relatively little progress towards reducing the subsidy. The only significant step in this regard is Hydro's proposal to increase rates for Provincial and Federal Government departments on the Isolated Rural Systems by 20 percent. This proposal is characterized as an initial step to achieve full cost recovery from Government agencies and departments. This limited full cost recovery will require ultimate rate increases of 280% for Government agencies over a five-year period in accordance with a rate plan that Hydro says it will submit to the Board in its next Rate Application. However, Hydro has not indicated when it will submit its next filing.[5]

Other than this Government rate increase, Hydro presently recommends that rural rates be maintained at a parity level with NP's retail rates. This results in a proposed rate increase of 3.7 percent for Rural Island Interconnected, Rural

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4 We do note, however, that rural deficit amounts have been allocated to NP in proportion to the demand, energy and customer totals for NP's industrial customers. The equity basis for this apparently inconsistent treatment of Hydro's directly served industrial customers and those served through NP, and how this squares with the horizontal equity provisions of the Public Utilities Act, is not explained in Hydro's Application.

5 Hydro has indicated, for a number of issues, that it has not developed a rate proposal, but that the omission will be covered in Hydro's next rate filing. Such issues include: (1) deferral of recommendations (including the phase-out of preferential rates and increased cost recovery from Isolated Rural Customer) concerning Isolated Rural Customer (Osmond at page 9), (2) the lifeline block for general service customers (Osmond at page 11), (3) allocation of rates for a five-year 100% cost recovery rate for Government agencies and departments (Osmond at page 12), and (4) additional rate changes in Labrador (Osmond at pages 13 and 15).

Isolated and L'Anse au Loup customers. This compares with a proposed 6.7 percent increase for NP which, when flowed through at the retail level together with NP's own unchanged distribution and other costs, is assumed to result in an overall retail rate increase of 3.7 percent.

Hydro also proposes to reduce rates on the Rural Labrador Interconnected System by an average of 13.1%. Thus, retail distribution rates in these markets will be below NP's wholesale rates. A significant reason for the proposed rate decreases on the Rural Labrador Interconnected System is a $2.8 million subsidy provided by revenues obtained from CFB Goose Bay under a secondary service contract that produces revenues substantially in excess of allocated costs. From an equity perspective the Board may wish to consider Hydro's basis for allocating this subsidy exclusively to Labrador Interconnected system customers who already have Hydro's lowest rates. Were it to be determined that the allocation of the CFB Goose Bay subsidy, like the allocation of the rural subsidy itself, has no basis in cost causality or economic efficiency, these funds could provide a direct offset to the overall rural subsidy burden.

RSP

Hydro proposes that its Rate Stabilization Plan ("RSP") balance cap be increased from $50 million to $100 million. The RSP balance reflects the amount of fuel costs that Hydro has incurred but has not collected from customers. One-third of the RSP balance is automatically incorporated into rates through an annual RSP adjustment. Hydro's RSP balance has grown substantially since 1992 as a consequence of Hydro's $12.50 fuel price in base rates, which has been substantially below actual market prices during much of the time. Hydro now projects that its cost for No. 6 fuel oil will be approximately $28 per barrel in 2002, decreasing to $26 per barrel in 2003. To moderate rate increase impacts, Hydro proposes to increase the base rate fuel cost to $20 per barrel and to raise the RSP balance cap from $50 million to $100 million so as to accommodate the substantially larger $98 million balance that is projected to accrue by the end of 2002. Despite the importance of No. 6 fuel oil prices, the Board has received little information concerning the forecasts adopted by Hydro and the conditions under which Hydro might adopt a hedging strategy.[6]

The rate design issue that this proposal poses for the Board is whether the social gain of deferring recovery of Hydro's fuel costs (with interest) justifies the pricing inefficiency and equity issues inherent in shifting costs between time periods and providing consumers with price signals that diverge from costs. The apparent philosophy behind Hydro's RSP is somewhat different than the reasons offered by most utilities for fuel cost adjustment clauses in their rates. Typically,

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[6] Mr. Osmond discusses both No. 6 fuel oil prices (at pages 1-3 of his pre-filed testimony) and the development of a hedging program (at pages 17-18). However, there is no information on which to assess the reasonableness of Hydro's forecasts for the price of No. 6 fuel oil, a forecast that relies upon the interplay of expectations concerning both the price of oil in U.S. dollars and the Canadian-U.S. dollar exchange rate. Although Hydro has rejected the implementation of a hedging program, both the nature of its analyses and the conditions under which such strategy would be adopted remain unexplained.

the purpose of fuel cost adjustment clauses is simply to account and compensate the utility for unforeseen fuel cost changes between rate proceedings. As such, these cost pass-through clauses have sometimes been criticized for allegedly undermining incentives for efficiency and cost control between rate proceedings. Hydro's RSP is different in that it is also explicitly intended to shift some portion of the foreseeable costs of serving current customers to future time periods. While the benefit of such cost deferral is clear for those current customers with high present value discount rates (i.e., customers whose time value of money exceeds Hydro's carrying costs), the cost burden transfer from today's customers to tomorrow's raises an equity question, and the economic efficiency benefits of cost reflective price signals are potentially impaired in both time periods.

The extent of this impairment depends, of course, on how cost reflective prices otherwise would be. If yesterday's deferral to today is approximately equal to today's deferral to tomorrow and tomorrow's deferral to a later day, and so on, there is little impairment to equity or allocative efficiency. Also, if rates without the RSP are not particularly good price signals to begin with, the RSP impact is not as likely to be a significant issue and might even improve the price signal rather than undermine it. In Hydro's case, major price signal issues such as the proposed energy-only rate for NP, the absence of time-of-use or seasonal rate variations, and the dominance of average cost prices rather than prices reflecting marginal costs, suggest that price signal changes attributable to RSP cost deferrals are not likely to be of compelling practical consequence.

Non-Firm Industrial Rates

In its 1993 Report, the Board concluded that it was not practicable to deal with the issue of interruptible power rates further because interruptible contract arrangements with Industrial Customers had not been finalized. The Board therefore concurred with Hydro and NP to defer the further consideration of cost allocation and rates for interruptible power users.

In this filing Hydro proposes a $1.50/KW per month demand charge (a reduction from $7.36/KW per month) plus a fuel based energy rate (without any RSP burden) for interruptible industrial customers on the Island Interconnected System. This interruptible demand charge is quite low in comparison to Hydro's other proposed industrial rates and produces total charges for these customers that are substantially below charges for firm service industrials and NP. For example, comparing the interruptible demand charge with the industrial wheeling rate (.695¢/KWh), a 50% load factor wheeling customer would pay $2.54 per KW vs. $1.50 per KW for interruptible service demand. The proposed interruptible demand rate is also far below the proposed firm demand rate of $7.01/KW per month. Assuming the same energy charge for interruptible usage as for firm industrial (2.309¢/KWh), an interruptible customer with a 50% load factor would pay 2.72¢ per KWh (the price with an 80% load factor would be 2.56¢) versus 4.80¢ per KWh for firm service to NP (or 4.23¢ per KWh for a firm service industrial with a 50% load factor.).

The logic supporting such large price differentials for interruptible customers is that their interruptible status frees them from most cost responsibility for fixed plant investment. This rationale is seldom entirely valid. In this case, interruptible customers benefit greatly from the low cost energy that is made available to them only because Hydro has invested in capital intensive generation capacity with low running costs. Indeed, this expensive baseload capacity's major virtue is relatively inexpensive kilowatt hours. The interruptible customers who benefit from these low running costs should, therefore, pay a reasonable share of the plant costs that were specifically incurred to obtain the low cost energy that they consume. As explained above, capital intensive base load generation should be built instead of lower cost peaking or cycling capacity when the tradeoff between the high capacity costs of baseload plants and their low running costs so warrants. Since interruptible customers benefit from this tradeoff directly and in proportion to their energy consumption, they should clearly be charged for a portion of the capacity costs that enable them to enjoy low energy costs.

Additional Issues

In addition to the cost allocation and rate design issues outlined above, there are several other points that the Board may wish to consider. First, in accordance with a Board recommendation in its 1993 Report on cost of service methodology, Hydro has classified all of the fuel costs for gas turbine and diesel generators in the Island Interconnection System as demand costs rather than energy. Although it is apparent that the generators that use this fuel exist for peaking purposes, the fuel costs are clearly variable operating costs associated with plant usage whenever this capacity is dispatched and not just at the time of the coincident peak demand. Typically, only a very small percentage of these fuel costs would be associated with CP demand. Consequently, unless there are other reasons for this unusual allocation of fuel costs, the Board should give consideration to revising this recommendation.

Second, Hydro has used system load factor to classify the costs of purchased power obtained from non-utility generators ("NUGs") to demand and energy, but has assigned all costs of purchasing power from industrial generators to energy. Unless there are fundamental differences between these two types of purchases (e.g., a high probability that industrial purchases will not be available at the time of the system peak), it would be preferable to apply the same cost classification procedures to both types of purchases.[7]

IV. RECOMMENDATIONS

Based on this review of Hydro's proposed cost of service methodology and rate design, we offer the following recommendations:

- Hydro should prepare and file rates reflecting seasonal cost variations. A utility with a winter demand double its summer demand, that allocates all of its demand costs between customers on the basis of winter peak demand, should have seasonally differentiated rates.

- Marginal cost considerations should receive greater attention in designing rates. This can be accomplished within a fully distributed, embedded cost context and need not adhere to "pure" marginal costs theories. In addition to facilitating the cost-reflective design of seasonal rates, consideration of marginal costs may warrant time-of-use rate differentials, facilitate the specification of cost-effective interruptible service discounts and eliminate pricing differences between

[7] The NUG purchase prices are on a seasonal basis, thus emphasizing the feasibility of a seasonal price structure for Hydro's own rates.

classes and customer categories that do not reflect cost differences.

- Hydro should propose cost-reflective rates for NP that charge separately for each classified cost category (e.g., demand, energy) and that vary between seasons and time-of-use in line with costs. This is an important step that is required in order for NP to develop retail rates for its own customers that accurately reflect actual resource costs and the costs (or cost savings) that will accrue to NP as its loads change over time.

- Hydro should classify all of its transmission network costs between demand and energy. This can be done in accordance with marginal cost principles (e.g., the marginal cost of transmission demand does not exceed the cost of connecting a peaker to the grid) or, at a minimum, in proportion to system load factor.

- Distribution network costs should be classified principally to energy and demand, and distribution demand costs should be allocated in proportion to non-coincident demand measures. Distribution networks are designed to meet local area load requirements. Other than customer specific costs (e.g., meters, service drops), the customer costs of a distribution network are best measured for rate design purposes as the cost savings to a utility if a customer leaves the system.

- The Board should consider developing an evidentiary record regarding the extent to which the rural deficit should be reduced and the extent to which universal service should be subsidized. Hydro should continue to cover the rural deficit based on equity considerations that the Board deems appropriate. One equitable way to cover the rural deficit without distorting price signals would be to fund it through marginal cost rate design procedures.

- If the Board chooses to implement rate design principles that reflect costs, consideration should be given to eliminating the RSP component that intentionally defers cost recovery to future time periods.