Report to

The Board of Commissioners

of Public Utilities

# of Newfoundland and Labrador

concerning

Newfoundland Power Company's

Study of Rate Designs Based on Marginal Costs

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Washington, D.C.

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Executive Summary

This Report assesses the study filed by the Newfoundland Power Company ("the Company" or "NP") titled A Study of Innovative Approaches to Rate Design Based on Marginal Costs and Time-of-Use Design Principles, here-in-after referred to as "the Company's Study". The Company's Study was prepared for the Board of Commissioners of Public Utilities of Newfoundland and Labrador ("the Board") pursuant to the Board's Order No. P.U. 7 (1996-1997) wherein the Board ordered NP to study marginal costs and innovative rate designs. The Board has requested this critical assessment of the Company's Study.

The Company's Study is in three main parts. The first part is an estimation of the marginal costs of providing electric service on the NP system. The second main part is a survey of innovative rate designs in Canada and the U.S. and the third main part is the development of a rate design on the Company's system based on NP's marginal cost analysis.

The Company's Study estimates four main components of marginal electric power costs. These are (1) energy-related generation costs, (2) demand-related generation costs, (3) demand-related transmission and distribution costs, and (4) customer-related distribution costs. The Company's study does not view any transmission or distribution costs as being energy-related. The Company's estimates of energy-related marginal generation costs are based on the running costs of its Holyrood generating units. Marginal demand-related generation costs are estimated using the fixed costs of a gas turbine peaking plant. Marginal transmission costs in the Company's Study are estimated by annualizing projected incremental transmission investment and fixed expenses on a per kW basis over the next five years. Additional demand-related transmission costs arise due to

NP's use of a portion of the transmission system owned by Newfoundland and Labrador Hydro (Hydro). These costs are calculated based on the annualized investments in the Hydro transmission system that are specific to NP. Distribution marginal costs are arrived at by annualizing future incremental investments and expenses and then separating these costs between demand-related and customer-related components based on certain Company judgments. Marginal customer costs are the sum of certain distribution facility costs deemed by the Company to be customer-related plus the incremental cost of meters and service connections and other customer services expenses such as meter reading and billing.

The second major part of the Company's Study is a survey of innovative rate designs in the U.S. and Canada. This survey seems to be a fair assessment of the current state of rate design.

The third major part of the Company's Study is the design of marginal cost-based rates using the marginal cost estimates arrived at in the first part of the Study. A potential concern here is that the Company adjusts certain of its estimated marginal cost rate components downward to reconcile the revenue collected under these rates with the same embedded class revenue requirements that are recovered under its current rates. The Company's current rates are based on its last embedded cost study.

Our overall assessment of the Company's Study is that it reflects a reasonable attempt to comply with the Board's Order. There are, however, certain critical areas where alternative and arguably superior methods would have produced significantly different results. Cost allocation, classification, and rate design are not precise mathematical sciences. They require numerous discretionary assumptions and methodological choices that have predictable impacts on the end result. For example, choices that result in allocating more costs to on-peak users and less to off-peak ones will tend to shift revenue responsibility from large, high load factor customers to smaller customers. Likewise, recovering costs through flat per customer charges instead of on a usage basis, will shift a larger portion of total revenue responsibility to smaller customers. In each case, the reverse is also true – recovering costs on the basis of energy consumption will favour smaller customers because their load factors (i.e., total energy to peak demand ratio) and energy per customer ratios are lower. In this case it is our opinion that while the Company's Study must be deemed to be reasonable – at least within the relative context of marginal cost pricing approaches that have been implemented elsewhere in recent decades – critical discretionary choices that favour larger, high load factor customers have been made. Reasonable methodological modifications to these approaches would yield significantly different results.

In many of these discretionary situations there is no purely correct answer. From a technical economic perspective there is no denying that the discretionary choices involved in cost allocation, classification, and rate design are, to a large extent, "arbitrary".[1] In most of these cases, choosing the "best" methodology involves business or public policy goals. From a purely business perspective, choices that the Company has made that shift costs away from large customers make some sense. Large customers' demands are often much more price elastic than small customers' demands. Large commercial customers sometimes have alternative fuel choices or they are able to employ conservation measures or choose plant locations to reduce power costs. Likewise, large commercial and

[1] In commenting on the use of long-run marginal cost in ratemaking, Bonbright has said: "when used as a practical standard of ratemaking, the concept should be defined only in general terms and should be left for what ever nicer definition may be required in light of the particular ratemaking problem" (James C. Bonbright, Principle of Public Utility Rates (New York: Columbia University Press, 1961), p.325).

some large residential customers can choose between oil or propane (or, in some markets, natural gas) and electricity for spaceheating and other appliance uses. Small customers have less price-elastic demands for their lighting and motive power needs. Consequently, lower rates for large customers may result in greater total sales.

From a public policy perspective, shifting costs from energy charges to peak demand or per customer charges in order to promote sales to large customers with price elastic loads may be less appealing. In any event, the analysis in this Report demonstrates that by directing the Company in key methodological areas, the Board has the discretionary ability to aim cost allocation, classification, and rate design in those directions that it deems will best serve the public interest.

The main areas for potential disagreement with the Company's Study involve the classification of production, transmission, and distribution costs among demand-, energy-, and customer-related components. In addition, the Company's Study also results in distorted marginal cost price signals because it adjusts marginal cost rates so that they will recover the same revenue requirement from each class that is now being collected from that class under embedded cost rates. If marginal cost ratemaking is implemented, it would be far more accurate to allocate revenue requirements to classes based on marginal cost principles or to omit the step of creating class revenue requirements altogether and, instead, apply the same marginal cost rates to all classes (with adjustments for delivery voltage level and any other real cost factors) and to adjust these rates uniformly to accommodate the total revenue requirement. This approach would effectively establish each class' total revenue in relation to its marginal cost responsibility.

With respect to the Company's classification, there are two major concerns. First, all transmission investment and fixed expenses are classified as demand-related costs and none are classified as energy-related costs. Second, the Study also classifies an exceedingly large portion of distribution investment and fixed expenses as customer-related costs rather than being demand- or energy-related. The Company's reliance on a National Economic Research Associates (NERA) method of classifying distribution costs using a so-called “facilities approach” is flawed because the method classifies investments and fixed expenses related to changes in demand and energy needs as customer-related.

Because marginal costs calculated in the Company’s Study are used to design time-of-use and seasonal rates, it follows that, to the extent that marginal cost measures are flawed, the rate designs are flawed.

I. Introduction

This Report assesses the study filed by the Newfoundland Power Company ("the Company" or "NP") titled A Study of Innovative Approaches to Rate Design Based on Marginal Costs and Time-of-Use Design Principles, here-in-after referred to as "the Company's Study". The Company's Study was prepared for the Board of Commissioners of Public Utilities of Newfoundland and Labrador ("the Board") pursuant to the Board's Order No. P.U. 7 (1996-1997) wherein the Board ordered NP to study marginal costs and innovative rate designs. The Board has requested this critical assessment of the Company's Study.

The Company's Study estimates various marginal cost components of electric power supply on the NP system. The major areas for disagreement with the Company's Study relate to the classification of costs and the failure to use marginal costs in determining class revenue requirements. We start with principles of marginal cost ratemaking in Sections II - V and then turn to the details of NP's analysis in Sections VI and VII.

II. The Traditional Approach to Rate Structure Determination

To understand the innovative aspects of marginal cost ratemaking, it is useful to explain briefly the way that electric utility rate schedules have traditionally been determined. Each electric rate schedule, or tariff, is a price list for electricity service. In general, customers (or "ratepayers") are grouped into several classes, and each class purchases its electricity service from a different rate schedule. 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 two or three major business service categories, divided either between commercial and industrial customers, or according to the size of the load. Likewise, as in NP's case, 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 classes for services such as street and highway lighting, water pumping (for irrigation), etc.

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.

Rates are multiplied times the total quantity of electricity used by the customer in a month. The price level may vary with the quantity used – typically a higher rate for the first so many units of electricity and lower rates for subsequent quantities. This is a so-called declining block rate structure. There may also be seasonal price differences, and there is typically a flat customer charge or minimum monthly bill for each class of service. Residential electricity is priced per kilowatt-hour[2] while non-residential rates typically have both a kilowatt-hour (energy) charge and a maximum monthly kilowatt (demand) charge. 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 allocation of a utility's total cost or revenue requirement among classes is done using a class cost of service study. A traditional class cost of service study

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2 A kilowatt-hour (kWh) of energy is, as the name implies, one kilowatt of power for one hour. A kWh is the amount of electricity required to operate a 100 watt light bulb for ten hours (or a 1,000 watt bulb for one hour).

allocates the total cost of service, which is all of the costs that comprise the utility's revenue requirement, among the various customer classes. The costs are grouped into functions, such as demand, energy and fixed customer costs, and each functional total is allocated among the classes in proportion to the use made by the classes of each function. For example, fuel costs are generally assigned to the energy function and allocated among the classes in portion to the classes' energy use (kilowatt-hours); while meter costs are generally assigned to the customer function and allocated among the classes in proportion to the number of meters. An important characteristic of the traditional class cost of service study is that it is based upon actual total or "embedded" costs, and these costs are usually reflected in rates at the average unit level (i.e., per kWh, per customer, etc.).

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.[3]
- 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 class revenue responsibilities are determined in accord with marginal cost principles rather than the embedded, average cost principles that are the foundation of traditional class cost of service studies.

III. Steps in the Process of Developing Marginal Cost Electric Utility Rates

The first and in many ways the most important aspect of developing marginal cost rates is the acquisition of the necessary data concerning sales, loads and costs. After the necessary data have been gathered, there are four analytical steps required to construct a complete set of marginal cost rates. These are as follows:

1. The first step is to choose the rate periods in which the rates will be different. This choice must be made with reference to the load curve, so that rates can be made higher in peak periods, when loads and incremental costs are greater; and lower in off-peak

3 Note that this is not the likely result when, as in NP's study, 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. Reasons for functionalizing a substantial portion of hydroelectric dam costs as energy-related are discussed below. These reasons are essentially the same as those for estimating the marginal costs of demand based on the

periods when loads and incremental costs are lower. Also, there may be one or more intermediate or shoulder periods, when loads are between the peak and off-peak levels.

The purpose of choosing different rate periods is to identify the hours when demand is high, so that the costs of providing capacity to meet these demands is charged against those responsible for causing the need for capacity by consuming during peak hours.

2. The second step is to determine the marginal cost of the components of bulk power supply. The first of these components is the marginal cost of capacity for meeting peak demand. The other component of the marginal cost of bulk power supply is the running or energy costs (principally fuel) of generating additional kilowatt-hours of electricity in each of the several rate periods. Energy losses between the generating plants and customers must be accounted for so that the rates can be properly applied to service as measured at customer meters. The selection of the rate periods and determination of the marginal costs of bulk power supply is also an interactive process, because the marginal cost differences help to identify the proper rate periods.

   These first two steps are based upon hourly load data for an entire year, and upon so-called system lambdas (i.e., the running costs of the marginal generating unit in each hour).

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capital cost of a CT peaker, and the same logic should guide both rate design and cost allocation methods.

3. The third step is the calculation of the costs related to the other functional services provided by electric utilities, namely transmission, distribution, customer costs, and administrative activities. Determining the correct marginal costs for these other functions is often more difficult and problematic than for bulk power supply, and proper assignment of these costs among rate periods is less important to the concept of time-varying rates than for bulk power supply costs. Also, electricity consumption decisions (i.e., price elasticity of demand) are less sensitive to these other cost elements than to bulk power supply prices. Consequently, average costs are sometimes used for these rate components without seriously impairing consumer decisions or the overall benefits of marginal cost pricing.

4. Electricity rates are per-unit prices, and costs must therefore be stated on a per-unit basis before they can be expressed as rates. To express costs on a per-unit basis, one must know how many units of each service are being provided by an electric utility. The fourth step is therefore the construction of the billing determinants needed to establish time-varying rates. These billing determinants are the number of units of each service, such as the total number of kilowatt-hours of energy in each rate period, the total number of kilowatts of peak period demand, and the total number of customers for which the utility provides service.

Since the use of marginal cost rates will not necessarily yield revenues equal to total costs, it is generally necessary to adjust the marginal cost rates to meet a specified revenue requirement.

IV. General Principles of Marginal Cost Estimation

There are two main reasons for pricing electric utility services to reflect marginal costs. Marginal cost pricing (1) increases the economic efficiency of resource use in the electric utility industry, and (2) increases the equity with which the costs of these resources are borne by ratepayers. Marginal cost pricing reflects the fact that the cost of supplying electricity is greater at those hours of the day, week, and year when demand for electricity is relatively high (peak periods), and less at those hours when demand is relatively low (off-peak periods). Marginal cost, time-of-use rates signal these cost differences to electricity consumers. Consumers are then free to shift some of their demand from higher cost peak periods to lower cost off-peak periods if the savings warrant the effort, or not shift if the value of peak period consumption justifies the cost. In this way, marginal cost pricing permits free market forces to increase the efficiency of resource use by more closely matching rates and costs. In this way, each unit of electricity purchased is worth at least as much as its cost of production (marginal cost pricing is "efficient"), and each ratepayer pays the costs of the electricity he uses, and gets to use the services that he pays for (marginal cost pricing is "equitable").

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.[4] Second, this approach to ratemaking provides the users of electric power with price signals that reflect

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4 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,

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 relatively scarce. The economist refers to this most important common sense result of proper pricing as "allocative" or "production efficiency".

For purposes of estimating marginal cost, 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, 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 the source of the bulk power supply, to a load center whether that power is generated by the utility itself or purchased from another utility. The third function, distribution, includes all the costs associated with distributing electric energy from the transmission system to individual customers at usable voltage levels.

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 detail in analyzing cost causation. Customers who take service at primary voltages, and make no demand on the secondary system, would then bear

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time-of-use rates clearly constitute a continuation of the historical approach to equity in ratemaking as opposed to "social ratemaking".

only the costs related to the construction and operation of the primary distribution system.

These various functions are then further analyzed to determine the "classification" of each function. 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.

The major area for disagreement with the Company's estimated marginal costs relates to the classification of various investments and expenses. 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 entire pattern of loads, and not just the level of peak demand that must be met. If generation capacity were installed only to meet maximum system demands, then units with low capital cost (but generally high operating costs) would always be installed. However, baseload units with high capital costs (but low operating costs) are installed if they can be run long enough to generate enough fuel savings to more than offset the higher capital expenditures. Hence, these costs are incurred not only to meet peak demands but also to serve year-round energy requirements at lower costs.[5] These same principles are true for capital intensive, high voltage transmission grids that deliver power from these plants and tie them together in an integrated network. Baseload plants and their associated transmission grids are used to deliver 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 just peak hour demand.

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 in their 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. The capital intensive but operationally efficient generating plants built to serve base loads are called baseload generating units.

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 winter 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, of course, the capital cost of storage capacity is virtually all energy-related and should not be allocated or recovered in proportion to peak demand.

If a utility's goal is simply to meet peak demand, it surely would install less costly local peaker plants. Peakers have a much lower capacity cost but are more expensive to run. But, since they only run during peak times, the higher running

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[5] As noted below, both Alfred Kahn and James Bonbright explicitly recognize this principle.

costs are justified in order to save on capital costs. Generally, then, it is appropriate to classify a significant portion of generation and transmission plant and fixed expenses as energy-related and these cost should be recovered from off-peak users.

As discussed below, NP's Study recognizes this important principle for generation but not for transmission plant investments. Utilities typically use transmission for two purposes: to reduce generating costs and to mitigate the need to add resources. 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 integrated with power production at other locations and transmitted over high-voltage transmission to load centers. The result is a savings on energy-related generating costs at the expense of greater transmission costs. In the case of NP, most transmission investment and expense is clearly related to the provision of less costly energy from remote locations rather than to meet peak demand, something that the estimates in the Company’s Study do not reflect.

Transmission facilities also 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 it transmission grid to achieve optimal dispatch. Hence, the transmission grid helps reduce energy costs and this energy component should be recognized in the classification of marginal costs.

Plant costs are also incurred to minimize environmental externalities. Environmental externalities are related to production output. Since the level of these externalities is correlated with kWh output, generation or transmission investments made to reduce such externalities are properly classified as energy-related investments.

The implication of mis-classifying costs can be understood more fully by considering the alternative classifications of two kinds of plant -- a baseload plant and a peaking plant. The baseload plant will provide low-cost energy but at a high capital cost, while the peaking plant, being expensive to run, will provide energy at a higher cost, with a low capital cost. If the incremental capital costs of the baseload unit are classified as demand-related and these costs are incorporated into peak-hour or seasonal rates, then the customer incurring that demand cost will, in part, be subsidizing the low-cost energy produced by the baseload plant. In particular, a customer with a low load factor (i.e., one with high demand and low total energy consumption) could legitimately argue that his demand was not the reason that the baseload plant was constructed, and he should not bear the burden of its costs, at least not in disproportionate relation to his energy consumption. For the purpose of meeting this customer's requirements, the demand could be met with a lower-cost peaking plant. However, a customer with a high load factor would prefer that his requirements be met with the baseload plant because the lower energy costs will reduce his total bill. Clearly then, the baseload plant is constructed to meet energy requirements, and not to meet requirements of demand; but in either event the cost responsibilities among customers may be significantly affected if such a mis-classification is made.

When a utility improperly shifts cost from an off-peak rate to an on-peak rate (or between seasons) by mis-classifying costs, rates will diverge from the cost of providing service and distort allocative efficiency. Achieving allocative efficiency means achieving the best combination of production outputs possible 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 material resources) to reflect the resource costs of producing them. Allocative efficiency means that consumption should be curtailed when the value of electricity consumption (value determined by consumers' preferences and demands) is less than its resource cost – i.e., less than the value of the product that could be produced instead. Allocative efficiency also 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 desire at the prevailing price level.

When customers pay less than marginal costs for a kWh of electricity, as would be the case if too much cost is charged to peak demand, this will cause excessive energy demands and distort the allocation of resources. Likewise, when customers are charged more than marginal costs, consumption will be artificially curtailed and welfare will be reduced. Consequently, economic efficiency goals will be defeated if marginal costs are estimated in a manner that ignores cost causation. Because the excess investment cost of a baseload generating plant over the investment cost of peaking capacity cannot properly be treated as part of the marginal cost of meeting peak demand, the question arises as to how this additional fixed cost of baseload generating capacity is to be recovered.

The first part of this answer is the observation that marginal energy costs exceed average energy costs at all hours of the day and year; and thus energy prices based on marginal energy costs contribute to offsetting the revenue deficiency that arises if demand prices are based on marginal cost rather than on the higher embedded cost of baseload capacity. The second part of the answer is that these two effects exactly offset each other in certain idealized conditions. The most important of these idealized conditions is that the capacity mix of the utility be balanced in such a way that it meets the actual load pattern at the lowest possible total cost for capacity plus energy. This condition is referred as optimal system configuration.

If there is too little baseload capacity, then peaking units will be running for too many hours in the year, and total costs could be reduced by having more baseload capacity in the mix. Plant costs would be increased, but fuel cost savings would be achieved in enough hours to more than offset the additional plant costs. Conversely, if there is too much baseload capacity, some of it will be running for too few hours to provide sufficient fuel savings to cover its higher initial cost. At the most efficient point, where the capacity mix is balanced, the revenues from demand and energy rates based on marginal costs will exactly equal the total (or average) costs on this idealized system, and this is the link in economic theory between marginal costs and the utility's total revenue requirement.[6]

In addition to allocative efficiency, there are also equity considerations associated with proper cost classification and the resulting cost estimates and rates. The classification of an excessive portion of fixed costs as demand-related will permit a utility to favour its high-load-factor customers (who have more elastic demands) over low-load-factor customers. This is because high-load-factor customers tend to consume more at offpeak times than do low-load-factor customers. Hence, peak-related marginal costs that have been estimated

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6 This balancing of marginal and average costs depends also upon the absence of further economies of large scale (beyond those already achieved by the utilities), and upon the presumed equality of embedded costs of older plants with the current plant costs used to balance the capacity mix. This

improperly by including non-peak-related costs will enable the utility to shift costs to low-load-factor customers and favour price-sensitive, high-load-factor customers. While this may make sense from the business perspective of maximizing sales and profits, it is less appealing from a public policy point of view.

V. **Basis of Assessment**

Three well-regarded reference guides were used in evaluating the Company's Study: (1) James Bonbright's Principles of Public Utility Rates (New York: the Columbia University Press, 1961), hereinafter, "Bonbright"; (2) Alfred Kahn's The Economics of Regulation-Principles and Institutions (Cambridge, Massachusetts: The MIT Press, 1989), hereinafter, "Kahn"; and (3) the National Association of Regulatory Utility Commissioner's Electric Utility Cost Allocation Manual, (1992), hereinafter "the NARUC Manual." In general, the NARUC Manual provides the most explicit guidance in methods of calculating utility marginal costs. Kahn and Bonbright provide a far more rigorous theoretical underpinning for marginal cost ratemaking, with Kahn providing the most thorough and detailed treatment. As such, it makes sense to summarize the major theoretical rationale and conclusions of Bonbright and Kahn before discussing the implementation procedures in the NARUC Manual.

Bonbright

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, Principles of Public Utility Rates.

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last assumption is almost certainly violated in inflationary times, and that is one reason why prices based on marginal costs do not exactly match average costs.

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 Public Utilities Act 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 Public Utilities Act, 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 three 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 conservation, efficiency and equity emerged as the hallmark of modern electric utility rate design.

Bonbright begins his treatment of marginal cost pricing by pointing out certain ambiguities in distinguishing between short-run and long-run marginal costs. He concludes that both long-run and short-run concepts are needed for marginal cost ratemaking.

While Bonbright endorses the use of long-run marginal costs in setting rates (Bonbright at 336), he provides only limited guidance on the specific calculations to be followed. Significantly, while stating that off-peak users should not pay for capacity costs, Bonbright clearly recognizes that the major portion of baseload plant capital costs are energy (rather than capacity) related and that these should be borne by all consumers of energy:

> If an electric power station were constructed for the sole purpose of supplying a peak demand occurring, say, only one hour per day, less efficient and hence less expensive turbogenerators (possibly with gas turbines) would be installed for the sake of maximum economy. Hence, when stations are designed to supply a 24-hour variable load, the additional costs of the more efficient generating units are theoretically chargeable to off-peak use.
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> (Bonbright, p. 354, fn. 15).

With respect to the treatment of customer costs, Bonbright notes that customer costs appropriately include the "costs of metering and billing along with whatever other expenses the company must incur in taking on another customer" (*Id.* at 347). But beyond these costs, Bonbright does not advocate the recovery of system costs through a customer cost charge:

> [T]he 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…. 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.
>
> What this…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). Indeed, 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 cost of the minimum-sized distribution system.
>
> (*Id.* at 347-48.)

<u>Kahn</u>

Kahn's theoretical treatment of marginal cost pricing adheres to Bonbright's general principles and is quite extensive, covering two full chapters (Chapters 3 and 4 of Volume I). According to Kahn:

> "The central policy prescription of microeconomics is the equation of prices and marginal cost. If economic theory is to have any relevance to public utility pricing, that is the point at which the inquiry must begin.
>
> As almost any student of elementary economics will recall, marginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that would be saved by producing one less unit. Looked at the first way, it may be termed incremental cost – the added cost of (a small amount of) incremental output. Observed in the second way, it is synonymous with avoidable cost – the cost that would be saved by (slightly) reducing output." (Kahn, Vol. I, pp. 65-66).

Kahn's theoretical underpinning for efficient pricing in a capital intensive industry concludes that the short-run, variable cost is the most efficient price signal as it fully utilizes existing plants to the point where the value of marginal consumption is equal to the value of the foregone resource. In the case of electric utility costs, this could be interpreted to mean that the only cost relevant for pricing would be the running cost of generation and whatever slight, variable O&M exists for transmission and distribution systems. Kahn does, however recognize the impracticability of pricing at short-run marginal cost (mostly because short-run marginal cost pricing will not recover enough revenue to cover total costs, see Kahn p.83-86) and explains that some long-run cost concepts (including fixed or "sunk" capital costs) should be involved (*Id*. at 87). The use of long run marginal costs, according to Kahn, should be forward looking and, notably, should signal to users of the productive capacity at peak times the cost of satisfying additional demand. While observing that "capacity costs *as such* should be levied only on utilization at peak…", Kahn notes the key qualification of being served by the same type of capacity as follows:

> If capacity is not interchangeable, so that the same type of plant or equipment does not necessarily serve both peak and off-peak users, it is no longer true that peak consumption alone should bear all capacity costs.
>
> (Id. at 97).

Kahn goes on to illustrate the point using a decision by the British Central Electricity Generating Board (CEGB):

> In electricity generation, it is economical for short periods of time to use gas turbine generating units, which have low capital costs but high operating costs. These are inefficient for continuous utilization, but are less costly than installing regular capacity for just the extreme peak demands. In consequence, when the CEGB tried to incorporate the entire capacity costs in the demand charges, at about £10 a year per kw it found that some of its Area Board customers began to install their own gas turbines, at a cost of about £4 per kw, and therefore cut down their peak purchases. The Board correctly recognized that the true incremental or avoidable costs of supplying capacity that would be used for peaks of comparatively short

> duration…were not £10 but £4 per kw, and that the [balance] should therefore be borne by consumption during the longer period…
>
> (Id. at pp. 97-98).

Thus, in the actual estimation of utility marginal costs it must be recognized that certain capacity investments are made to serve year-round energy needs as opposed to peak demand.

NARUC Manual

As noted above, the NARUC Manual is the most straightforward practitioner's guide for the implementation of utility marginal cost rates. Perhaps relatedly, it does not always offer the most theoretically satisfying guidance. Rather, its mix of marginal cost principles with traditional procedures is more pragmatically directed, and there is often room for deviation from the Manual without doing harm to (indeed, in some cases, while improving) the attainment of marginal cost principles. In general, the NARUC Manual endorses some of the same economic principles of marginal cost ratemaking as advanced by Kahn and Bonbright but ignores or equivocates on others.

The Manual endorses the use of short-term energy costs as the energy-related marginal generation cost. Demand-related generation costs, according to the Manual can be estimated either by the peaker-deferral method or by examining the "generation resource expansion method." The peaker deferral method, which has been favoured here by NP, and which we deem to be reasonable, simply calculates the carrying charge of the fixed cost of the least-cost peaking plant and uses that as the estimate of the demand-related marginal capacity costs. Marginal energy costs under this method generally vary over time in accordance with the running cost of the marginal generating unit, or, in engineering terms, the dispatcher's "system lambda." In NP's case, we understand that the Holyrood plant is marginal (i.e., output at this plant is increased or reduced as needed to match load) at most times, and, therefore, NP's marginal energy cost is generally the running cost of Holyrood.

The NARUC Manual's “generation resource expansion method” offers an alternative means of calculating marginal generating capacity cost. Under this method, the least-cost generation resource plan that a particular utility would undertake to meet additional demand over a foreseeable period is annualized to determine the demand-related generation capacity costs. The Manual presents both the peaker deferral and generation resource expansion methods but endorses neither of them. While the NARUC Manual does not mention it, given the assumption of an optimally configured system, the peaker method and the resource expansion method will produce the same results. That identity, of course is a is a theoretical nicety absent in the real world. Thus, application of the two methods to actual systems can produce significantly different results.

With regard to estimating marginal transmission investments, the NARUC Manual presents several, closely-related methods which basically attempt to estimate the change in transmission investment and fixed expenses as a result of increases in demand. These marginal costs are then considered peak-related and paid for by peak users. The Company's Study conforms generally with this approach – which we consider to be conceptually weak. Some methods presented in the NARUC Manual account for the fact that some transmission investments may be related to goals other than meeting peak demand; for example, by identifying certain transmission investments as related to the generation function. Such a recognition is important in accurately estimating marginal costs. The lack of this recognition, in our opinion, is one shortcoming of NP's analysis. As explained more in the next section, most transmission investments are related to base load generating plants and their off-peak generation and, thus, should not be paid for by peak users.

With respect to distribution costs, the NARUC Manual identifies, as most analysts would, customer-related distribution costs as those required to connect a customer to the system, (i.e., meters, service line drop, and certain billing and accounting costs). In addition to these customer costs, the NARUC Manual engages in a discourse about additional costs that might be properly classified as "customer-related." Without endorsing the concept, it explains the main method some analysts use to estimate the customer-related portion of distribution facilities (and consequently costs). This method is the so-called minimum system method that was singled out for criticism by Bonbright (see above). Under this method, which is conceptually similar to the "facilities approach" favoured by NP, a minimum distribution system is estimated that would be necessary to connect a customer to power supplies. This minimum system is usually estimated using statistical analysis which tries to find a correlation between investments and number of customers in order to obtain an estimate of the cost of providing all customers minimum voltage, but no power. But, as Bonbright implied, there is little or no relationship between this estimated value and the incremental resources that would be saved by a customer charge that encouraged an existing customer to forego service. Since the minimum system concept works, at best, to provide a meaningful cost signal only to a new customer who is considering the receipt of service at a new location that will require distribution network expansion but offers no meaningful signal to already existing customers, we see it as little more than an artificial rationale for attributing distribution network costs to a rate component that has no price elasticity of demand (and that falls heavily on small customers).

VI. NP's Marginal Cost Study

The main area for disagreement with the Company's Study is the classification of costs among demand-, energy-, and customer-related components. The Company has also mixed embedded cost and marginal cost concepts in reconciling marginal cost rates with embedded class revenue requirements.

The Company has made certain assumptions and discretionary choices that result in the recovery of a larger portion of total revenue requirements through on-peak transmission charges and customer charges than would be the case with alternative classifications. This tends to benefit large, high-load-factor customers and attribute more costs to small, low-load-factor customers. It also runs counter to one purpose of marginal cost ratemaking by attributing a disproportionate share of costs to rate elements with low price elasticities of demand, thus minimizing the impact that rate increases will exert on sales.

The Company's "facilities charge" method of distribution plant cost classification rests on the assumption that the capital investments and fixed expenses undertaken to connect and serve new incremental customers are the correct measure of marginal customer costs. But because this measure greatly exceeds the cost of serving existing customers or the cost savings that would be realized as the result of an existing customer departing the system, it gives the wrong price signal to everyone except a potential customer who is considering a new hook-up. Again, the Company's approach serves to attribute a larger share of total costs to rate categories where there will be little or no impact on sales and more to small customers and less to large customers.

A. Marginal Generation Costs

In general, the Company's estimates of marginal generation costs are reasonable. A minor drawback relates to that fact that a large portion of NP's power (about 90%) is supplied through purchased power contracts with Newfoundland and Labrador Hydro (Hydro). The Company's Study attempts to estimate its own marginal generation costs by estimating the marginal cost to Hydro of supplying NP with purchased power. NP, however, does not purchase power at Hydro's marginal costs but purchases at a constant, average-cost, volumetric rate. Thus, incremental increases in consumption on the NP system result in changes in NP's costs at a constant rate. But, since marginal costs are supposed to reflect society's costs associated with incremental changes in consumption, Hydro's marginal costs are the best for this purpose. Unfortunately, this means that changes in demand will have different effects on NP's revenues and purchased power costs. It would be far preferable if NP paid proper marginal-cost based rates for the power it purchases from Hydro and if these rates were then used to estimate NP's marginal costs of serving retail customers.

In estimating Hydro's marginal costs, the Company assumed that demand-related marginal generation costs correspond to the cost of a peaking plant, estimated at $83.1/kW/year. Energy-related marginal generation costs were estimated using Hydro's Holyrood thermal plant, which, according to the Company, provides incremental energy for the system during almost all hours of the year. For off-peak times, the Company used the running cost Holyrood, which is about 4.03¢/kWh. For on-peak times, the energy-related marginal cost was estimated by weighting Holyrood's running cost by 95% and the running cost of a combustion turbine (approximated at 8.25¢/kWh) by 5%, for an on-peak energy-related marginal generation cost of 4.24¢/kWh. (See Appendix C, Schedules 3, 4, and 5 of the Company's Study.)

These estimates are reasonable under the assumption that Hydro has optimally configured its generation resources. On an optimally configured system, the installation of more expensive capital intensive plants are justified based on the fuel savings that can be achieved by running such plants many hours during the year. On such a system, an energy rate reflecting the running cost of the unit that is dispatched at the margin (in this case, Holyrood) represents the marginal energy cost to the system.

The Company's estimate of the peak-related marginal generation capacity cost using a peaker deferral method is also reasonable. Larger investments in capacity (e.g., as are required for hydroelectric dams) are clearly intended to reduce energy costs. These greater investments in capital intensive plants should be recovered through energy rates.

B. Marginal Transmission Costs

While the Company's marginal generation cost estimates are reasonable, the same is not true for marginal transmission costs. According to the Company's Study, marginal transmission costs arise from two sources: (1) the transmission investment and expenses incurred by Hydro to support bulk power transmission to NP and (2) NP's own transmission investments and expenses. The Company's Study improperly assumes that all incremental transmission costs are demand-related.

Utilities, as in this case, typically undertake transmission investments for two main reasons, both unrelated to meeting peak demand. The first is to permit the remote location of generating units, either to be near fuel or water supplies, or to ease environmental concerns. The other reason is to integrate generation resources in a manner that reduces the overall investment in and running costs of system plants. The true peak-related transmission marginal cost is no more than the cost of interconnecting a peaking plant to the integrated network. Since the Company's Study uses the peaker deferral method for estimating generation marginal costs, it would have made sense to apply the same principles in estimating transmission marginal costs. Transmission costs in excess of connecting a peaker to the system (typically less than $10 per kW), are costs related to decisions to invest in capital intensive base-load plants.

C. Marginal Distribution Costs

Most analysts agree that fixed monthly customer costs should include the costs of meters, meter reading, billing and connecting customers to the distribution system. In addition to these costs, the Company further classifies a portion of its distribution system investments as a fixed customer cost that is unrelated to the amount or level of electric service. This classification is based on a "facilities charge" approach that attempts to identify investments and expenses related to changes in the distribution system that result from the addition of new customers. For example, the Company's Study classifies as customer costs about 90% of primary and secondary extension investments and expenses. These costs are then allocated on a flat, per customer basis rather than in proportion to power demand or energy consumption. Because NP has a large number of small customers and fewer large customers, a high percentage of these costs are charged to small customers and there is no pricing impact on energy or demand rates. In fact, the costs of these facilities reflect their demand on carrying capability rather than representing only fixed costs that would be incurred independent of demand and load levels. Most fundamentally, NP's facilities charge 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 merely on the basis of customer counts.

Distribution facilities are sized and installed to meet the expected loads placed upon them, and not to meet a specific number of customers to be served. It therefore makes no sense to allocate the costs of the distribution plant on the basis of the number of customers being served in each rate class. The fact that an electric utility's distribution lines are sized and installed to meet customer loads and not customer counts is demonstrated in the following hypothetical example: 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 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 connections and meters will vary directly with the number of customers and there are likely to be some differences in transformer configuration, the local distribution facilities must be structured to handle a 1,000 kW peak load in each case, regardless of whether there are 4, 20 or 200 customers involved.

Distribution lines are part of an integrated network. They are not customer-specific facilities in the same sense as service drops or meters. Services and meters involve customer-specific costs. One electric customer neither uses nor benefits directly from another customer's service connection or meter. Consequently, regulatory commissions have frequently approved utility rate structures that recover meter and service connection costs through customer charges rather than demand energy charges.

Electric distribution networks are quite different. In most cases, if a residential customer on an electric utility system's intensive margin (i.e., a customer located within an established service area) drops off the system, that will not alter the design requirements of the integrated distribution network. Although a meter and service drop will no longer be required for that customer, the primary and secondary lines that served that customer will still be required to serve others. In short, the distribution system cost of maintaining service to a customer in an established area is very small, and it would therefore be a mistaken price signal to load substantial distribution system costs into the customer charge.

In pricing distribution service it is far more sensible to structure rates to reflect the marginal network costs of customers on the intensive margin (because that is where the vast majority of customers are located) and to deal with the system expansion costs of additions at the extensive margin through a rational system of developer contributions and/or one-time service extension charges. To confront the vast majority of customers who are located on the distribution system's intensive margin with price signals reflecting network extension costs at the extensive margin would be pointless, inefficient and unfair.

In order to rectify the Company's estimates, the marginal costs that arise from system usage should be classified as non-customer related. Table I summarizes a more appropriate split between customer- and non-customer-related costs.

Table I
Customer and Non-Customer-Related Distribution Costs Properly Classified

Cost Category	Non-Customer-Related	Customer-Related
Substation	$1.46/kW/year	
Primary	$4.51/kW/year	
Total Primary	$5.97/kW/year[7]	
Secondary	$3.73/kW/year	
Transformers	$16.20/kW/year	
Total Secondary	$19.93/kW/year	
Services		$57.0/wcust
Meters		$10.3/wcust
Customer Costs		$57.5/wcust
Total	$25.90/kW/year	$124.8/wcust

The non-customer-related distribution costs could be classified between demand and energy components. This is because the local distribution grid is designed both to deliver peak demands and to minimize energy losses. To the extent investments are made to minimize loses, these are energy-related investments. Because we have no data on which to base a separation of these costs between demand and energy, all non-customer related distribution costs are here assumed to be a result of investments to meet peak demand. Modification of this assumption would be warranted based on actual energy and demand data.[8]

7 The Company plans $4.00/kW/year of distribution-related substation investment beginning in 2001.

8 It would be reasonable classify a portion of the distribution plant as energy-related simply because, although sized to meet local peaks, the facilities are clearly used to meet both energy and demand requirements. One way to achieve such a division would be to use the average-and-peak split, basically using the system load factor as the share of the facilities classified as serving energy needs and 1 minus the system load factor as the share devoted to peak needs.

VII. NP's Marginal Cost Rates

A. Full Marginal Cost Rates

Table II, presents a summary of Newfoundland Power's marginal costs based on the adjustments suggested in the previous sections. Except for generation-related energy costs, all costs are escalated at an annual rate of 2.3%, consistent with the GDP deflator used in the Company's Study. Generation related costs are also escalated in accordance with the estimates in the Company's Study. Table III is a summary of full marginal costs by type of customer using 1997 costs. These costs are adjusted for loss factors (Appendix C, Schedule 15 of the Company's Study) and for customer weights (Appendix C, Schedule 22 of the Company's Study).

B. Rate Design

As discussed above, the best way to design marginal cost rates is to dispense with class revenue requirement constraints and to calculate rates uniformly for all customers on a company-wide basis. Where, as here, class revenue requirements are employed, the first step in the process of converting marginal costs to rates is to determine each customer class' billing determinants. Billing determinants are the classes' kWh consumption, peak kW demands, and number of customers. These billing determinants are multiplied times the corresponding full marginal cost estimates to determine a full marginal cost revenue amount. Typically, as here, full marginal costs rates will result in revenues that exceed the current revenue requirements. This is so because new investments and marginal system lambdas generally exceed historical and embedded average costs. Consequently, rates must be adjusted through a reconciliation process in order to bring the total revenue from marginal cost rates into line with the utility's total costs and revenue requirement. In the interest of efficiency, most reasonable reconciliation processes seek to reduce the rate components that are least likely to affect consumption decisions.[9] The rate component least likely to affect consumption decisions is the customer charge. While, at sufficiently high customer charges, some consumers may decide to forego electric service altogether, in reality, changing customer costs leaves incentives for electric consumption virtually unchanged. It is the least avoidable marginal cost and is, thus, the rate component that should be adjusted in reconciling marginal costs with revenue requirements when allocative efficiency is a rate design goal. Most analysts see the demand charge as the second least avoidable rate component and the energy charge as the most avoidable.

Once the marginal costs are reduced to accommodate the class revenue requirement through the reduction in the customer charge, demand charge, and/or energy charge, in that order, the reconciled marginal costs for each class multiplied times the class billing determinants equals the class revenue requirement.

As noted above, the Company's Study did not use marginal cost rates to establish class revenue requirements. Instead, the Company used the revenue level under current rates. But this class revenue requirement is based on an average, embedded cost study and, thus, is based on average, not marginal costs. This is a major weakness in the Company's rate design approach. The whole idea of estimating marginal costs is to design rates that provide good price signals. But if marginal costs are ignored in determining the cost each class imposes on the system and rates are set to recover class costs, the good intention of marginal cost ratemaking is undermined. For good marginal cost estimates, the Company's Study method should be changed so that marginal cost rates are determined on a

[9] See NARUC Manual, pp. 147-150.

company-wide basis (with appropriate adjustments to reflect voltage level and other cost differences) or, at least, so that marginal costs are used to determine class revenue requirements.

C. <u>Adjusted Rates</u>

The estimates in Table III and Table IV illustrate rates and revenues based on the residential marginal costs corrected as described above. In addition to the full marginal cost rates (as corrected), rates are also shown that are reconciled to the current class revenue requirement. The class revenue requirements are not based on marginal costs. Consequently, the reconciled rates shown are for illustrative purposes. Also included in Table III for the benefit of comparison are NP's full marginal cost rates and NP's reconciled rates.

VIII. <u>Summary</u>

The Company's Study generally estimates marginal generation costs in a reasonable way. However, the Company's marginal transmission costs and marginal distribution costs have been estimated in a manner that is at least controversial, if not altogether contrary to sound economic principles. With regard to transmission cost estimates, the company considers all transmission investments to be demand-related, even though most transmission investment is undertaken for the purpose of meeting energy needs. Since the Company employs the peaker method for estimating generation marginal costs, it makes sense to apply the same principles for estimating transmission marginal costs. Accordingly, the cost of connecting a peaking plant to the transmission grid is the marginal cost of meeting peak demand and only such costs should be paid for by peak users. The Company's estimate of distribution marginal costs also employs questionable classification techniques in deeming that distribution facilities costs should be recovered through a flat customer charge. This approach is similar to the "minimum system" method which has been soundly criticized. The best way to estimate marginal customer costs is to include only the costs of metering, line drops, and specific customer services. Distribution network costs are load related and are properly recovered through demand and energy charges.

Another major drawback of the Company's Study is that class revenue requirements are based on revenues under current rates which, in turn, have been based on an embedded cost of service study. The whole point of calculating marginal costs rates is to relate charges directly to the incremental or avoidable costs that marginal demands place on the system. If embedded cost studies are used instead of marginal cost studies to determine class revenue requirements, then important economic attributes of marginal cost rates are lost.