Q. Please provide the testimony by Mr. Baker from the 1993 proceeding on a Referral by NLH for the proposed cost of service methodology in which his "mini cost of service" method is presented, and which contains his exhibit GCB-5, which is reproduced in the Report.

A A copy of the direct evidence of G. C. Baker (dated September 9, 1992) and supplemental evidence filed September 21, 1992 in the proceeding of the Referral by Newfoundland and Labrador Hydro is attached.

PROVINCE OF NEWFOUNDLAND AND LABRADOR

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF the Electric Power Control Act

- and -

IN THE MATTER OF a Generic Hearing on, inter alia, the Cost of Service Methodology used by Newfoundland and Labrador Hydro-Electric Corporation.

DIRECT EVIDENCE OF G. C. BAKER

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Q. Please state your name and address.

A. My name is George Chisholm Baker. I reside at Kentville, Nova Scotia.

Q. Please outline your qualifications and experience.

A. I am a registered professional engineer in Nova Scotia and have from time to time held licenses to practice in other provinces and territories. I am self-employed as a consultant in matters relating to the regulation of electric utilities and have testified before this honourable Board on two previous occasions. My experience relative to electric utilities covers about three decades and includes most aspects of utility operation. My clientele has included regulatory agencies in five Canadian jurisdictions, a number of utilities and departments of federal and provincial governments.

Q. What is your involvement in the present matter?

A. I have been engaged by the Board and instructed to provide an independent opinion on the cost of service methodology proposed by Newfoundland and Labrador Hydro, and topics related thereto.

Q. What topics do you wish to address in your evidence?

A. Because this is a generic hearing, I shall first discuss cost of service studies generally in a regulatory context. This will explain the criteria I have used in forming opinions about the matters at issue.

Secondly, NLH uses the average and excess method and proposes to continue using it, so I shall outline the complexities involved in the allocation of demand costs and compare the characteristics of average and excess with those of other demand allocation methods.

Finally, I shall submit opinions on the cost of service methodology proposed by NLH as exemplified by the study included in its filing. These opinions relate to:

Input data
Functionalization
Classification of generation fixed cost
Classification of transmission fixed cost
Classification of distribution cost
Allocation of generation and transmission fixed cost
Allocation of other costs

Q. Please proceed with your comments on cost of service studies generally.

A. For many years, "Principles of Public Utility Rates" (Bonbright, 1961; Bonbright et al., 1988) has been a widely accepted reference often quoted in regulatory proceedings. According to the second edition: "Without doubt, the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service."

The cost of service study is the general and almost universally adopted approach to cost of service determination. It has become highly standardized (although many variations of methodological detail are both recognized and necessary). The general procedure is described in the (1973) NARUC cost allocation manual as follows:

"1. Identification and segregation of costs directly attributable to any particular service.

2. Arrangement of the remaining costs so that they can be allocated to the various groups of customers which are jointly responsible for their incurrence; and

3. Allocation of such costs in accordance with physically measurable attributes of the service to the customer class."

NARUC's description suggests, both directly by reference and indirectly as a consequence of the defined procedure, that causal responsibility for the existence of costs is the proper basis for their allocation.

However, Bonbright concedes that the consensus on cost of service is not so monolithic as might appear, because cost can (and does) mean different things to different people. To many utility people the relevant cost is embedded cost, because that is what determines the revenue requirement. To the economist, the relevant cost is marginal cost, because pricing a commodity at marginal cost can, on the basis of certain assumptions, be shown to result in optimizing the welfare of society.

The choice between embedded and marginal cost is in fact subject to fairly restrictive limits. Long-run marginal cost now in most cases exceeds embedded cost and few, if any, regulators would find it reasonable to allow a utility to raise more revenue than can be shown to be required on an embedded cost basis. Further, there is some ground for suspicion that the assumptions underlying marginal cost theory are flawed in the case of a regulated monopoly. Nevertheless, within accepted cost of service methodology some latitude exists for the application of marginal concepts; mainly in relation to the classification of generation fixed costs.

Regardless of the degree to which analysis may focus on future cost as opposed to sunk cost, the objective is to allocate cost on the basis of causal responsibility.

Another concept available for cost of service determination involves charges for use of the system, sometimes referred to as "user-pay". This concept will receive more detailed consideration in my review of the Average and Excess (A & E) method. For present purposes, it is sufficient to say that where a causal responsibility approach would result in some customer groups receiving part of their electric service at no charge, it is often held that a user-pay approach enhances equity.

One might well regard both causal responsibility and user-pay approaches as considerations of equity, or fairness, which would in that case constitute a sufficiently broad criterion for the selection of appropriate methodology.

On the subject of rate design, Bonbright et al. set out a number of desirable attributes which may be roughly paraphrased as accuracy, administrability, understandability, public acceptance, stability, equity and economic efficiency. It is interesting to note that in the 1988 edition, greater emphasis is placed on equity and efficiency than in the first edition.

In his prefiled testimony, beginning at page 3, line 23, Dr. Sarikas includes these attributes in his list of goals or objectives, and adds conservation, social goals, employment and protection of the environment. While all of these have no doubt been pursued in some jurisdictions, the social, economic and environmental objectives may or may not fall within the purview of regulators and in Canadian jurisdictions they are often the responsibility of other agencies.

GCB-14 sought to ascertain what underlying objective or criterion was used to determine the cost of service methodology proposed by NLH. The response expresses the view that a cost of service study is not an end in itself; that it is a tool for rate design; that objectives relate to rate design, not cost analysis; and that the most significant rate objectives are fairness and economic efficiency.

In his testimony in the preceding NLH hearing (Transcript, p. 721), Mr. Brockman said, "Causality is the guiding principle of all cost of service work."

The viewpoint expressed in GCB-14 is in my opinion far too permissive. To allow some of the objectives listed therein to influence an analysis which under the ordinary meaning of words and accepted usage purports to be a determination of cost responsibility would be a surreptitious approach.

If it is necessary to reflect social or other considerations in rates, then the necessary adjustment can be made separately following the determination of cost responsibility, as Newfoundland and Labrador Hydro (NLH) has in fact done in its cost of service study.

I tend to agree with Mr. Brockman's view, but consider it is a little too restrictive if it is interpreted to exclude user-pay considerations.

To form opinions on methodological issues, I have used the criterion of equity, giving greatest weight to causal responsibility. Efficiency issues are given consideration.

Q. What are the complexities which arise in the allocation of demand costs?

A. The accurate assignment of responsibility for demand cost is difficult and complex compared to the assignment of responsibility for energy costs. The difference arises because energy is a "conserved" quantity, while demand is not. For example, if two classes each use 2 GWh of energy (losses included), then the system must supply 4 GWh. But in the case of maximum demands, 2 plus 2 does not necessarily equal 4. If two classes each have a maximum demand of 2 MW, their combined demand on the system might be anything between 2 MW and 4 MW, depending on the degree to which the classes demands happen to coincide.

The difference between the sum of the class maximum demands and their combined total is due to the time diversity between the class demands. The ratio of the sum of the individual maxima to their combined maximum is called the diversity factor.

The diversity which exists in the system gives rise to a "diversity benefit". This benefit is the saving in cost realized because the system can serve the diversity portion of class demands without having to own, operate or maintain any plant for that purpose. How this diversity benefit should be shared between customer classes is one of the complexities which arise in the allocation of demand costs.

Under one early method of allocation, demand costs were apportioned on the basis of non-coincident demands (NCD). This method imposed a minimal requirement for data and its popularity was no doubt due in part to that fact. Until about 15 years ago the NCD method was used for allocation of generation and transmission demand costs by more Canadian utilities than any other method. It is still widely, and appropriately, used for the allocation of distribution demand costs.

Diversity benefits under an NCD allocation are distributed pro rata over each non-coincident kilowatt. It is thus the archetype user-pay approach.

The diversity which exists in the system depends greatly on the constancy of electricity use. This quality is measured by the "load factor", which is the ratio of average demand to peak demand. An infrequent or intermittent load would have a low load factor, and it would obviously have a lower probability of contributing to system peak demand than a load which maintains a relatively high level and therefore has a high load factor. A continuous and unvarying load would have a load factor of 1 and it could not possibly contribute to the system diversity because the whole load would inevitably fall on the system peak and no other user of the system could make part-time use of the capacity which supplies that continuous load. Yet under a non-coincident demand allocation, the continuous load would share in the diversity benefits to the same degree as the intermittent load--a flagrantly unfair result.

The coincident peak method allocates demand costs to each customer class in proportion to the coincident peak demand of that class. The rationale is that electrical systems are sized and costs are incurred for the purpose of meeting the system peak demand and that it is therefore appropriate to allocate costs in proportion to the class responsibility for causing such demands. This method has now supplanted NCD as the method most widely used by Canadian utilities.

Although clearly founded on the principle of cost causality, the coincident peak method has been criticized on two counts:

(1) A shift in the time of system peak can materially alter the allocation of demand costs between customer classes without any actual change in the cost of service. This effect is to a certain extent minimized if multiple peaks are used.

(2) Diversity benefits are inequitably distributed.

The latter criticism arises because no cost is allocated to off-peak use of the system. The argument is that off-peak users do not by themselves create the diversity benefits: if the on-peak users did not exist, plant would have to be provided, operated and maintained to serve a large part of the load of such off-peak users.

At the heart of the criticisms levelled at both coincident and non-coincident methods lies an inherent conflict between the concepts of user-pay and causal responsibility. The alleged shortcomings of both methods may have prompted the development of average and excess and related methods based on load factor or diversity factor.

Q. How does Average and Excess compare with other methods of allocation?

A. For the purpose of comparison, it is convenient to visualize demands as consisting of three parts:

(1) Kilowatts of average demand;
(2) Kilowatts in excess of average demand which contribute to the system peak (coincident excess); and
(3) Kilowatts of excess demand which do not contribute to system peak (non-coincident excess).

Within each of these categories, all kilowatts are treated the same under each method of allocation.

1. The NCD method makes an equal charge for each KW in all three of the categories set out above.

2. The CP method makes an equal charge per kilowatt to groups (1) and (2) above and makes no charge for kilowatts in group (3).

3. The Average and Excess method charge per KW is the same as the CP charge for group (1) and makes a lesser but equal charge for group (2) and (3) kilowatts.

In effect, the Average and Excess method distributes diversity benefits evenly over each kilowatt of excess demand, whether or not the said kilowatts contribute to system peak demand.

The situation is graphically portrayed in Exhibit GCB-1. An equation comparing Average and Excess with CP allocations is presented in Appendix 1, which also contains the derivation of other mathematical expressions used in this testimony to characterize the Average and Excess method.

Q. Do you have any further comments on the characteristics of the Average and Excess method?

A. Yes. Analysis of generation fixed cost usually discloses that some part of it is attributable to energy consumption. In that case, if a CP allocation is used, the part attributed to energy use is classified as energy cost and allocated to rate classes accordingly. The result is that high load factor classes are charged with a larger proportion of fixed costs and low load factor classes a smaller proportion than if the costs had been classified exclusively as demand.

However, where the A & E method is used it is a widely held view that the method itself makes a similar adjustment, and that classifying some of the fixed cost to energy before applying the A & E method would be a form of double counting.

This idea arises because the A & E method allocates a part of generation fixed cost to rate classes in proportion to their average demands. This is equivalent to allocating on energy use.

The hypothesis that the A & E method achieves the same result as classification of some fixed costs to energy is explored by analysis and tested by computing the effects of various allocation methods on NLH rate classes.

The relevant analysis is included in Appendix 1, section 3. It compares the effect of a load factor split of generation fixed cost under the CP method with allocation under the A & E method. The results show that:

(1) With the load factor split of costs under the CP method, the allocation to each class varies in proportion to the difference between class and system load factors. The cost responsibility of high load factor classes is increased and that of low load factor classes is decreased.

(2) The results of applying the Average and Excess method are quite different. The allocated cost is a function of both diversity factor and load factor, and there is no simple correlation between load factor and allocated cost. Nevertheless, it is shown that the degree of energy recognition provided by the A & E method is precisely zero. All the differences in impact between A & E allocation and CP allocation with no energy recognition are accounted for by user-pay charges on non-coincident excess and diversity benefits on coincident excess.

The effect of an A & E allocation on NLH rate classes is compared with the effect of classifying fixed cost to energy in Exhibit GCB-2. The data used is set out in GCB-2.1 and the allocated costs are shown in GCB-2.2. Results of A & E allocation are contained in GCB-2.2, column 4, and compared with the results of classifying fixed cost to energy in column 6. The effect of classification to energy is a reduction in cost for NLH rural classes as a whole.

By comparison the A & E method increases the allocation to Rural classes, despite the fact that the rural load factor is less than the system average. This occurs because the user-pay charges exceed the diversity benefits.

In summary, the A & E method is completely neutral as far as the recognition of energy responsibility is concerned. The commonly-held view to the contrary is completely unfounded.

Q. Does Hydro's cost of service study provide sufficiently detailed input costs?

A. There is a great disparity between various cost of service studies in the amount of detail included in the input costs. In some cases, cost of service inputs have already been processed into convenient form. At the opposite end of the spectrum, study inputs consist of book costs at a low hierarchical level. This affords the analyst full opportunity to distribute the costs accurately by class and function, and it affords all interested parties an opportunity to see exactly what was done.

As an example of the latter approach, one utility uses no less than 33 schedules to arrange all the input costs by class and function. This probably goes well beyond what is actually required. On the other hand, input costs which are too highly aggregated do not give the analyst an opportunity to make a proper disposition, particularly in the case of overhead items. The analyst has no alternative but to prorate such overheads on direct costs, whether or not proration is in fact appropriate.

Detail is particularly important in relation to distribution expense where differences of weighting as well as classification may be important.

Hydro's cost of service study appears to be a little on the shy side in this respect. Distribution costs are subdivided only into equipment, metering, customer accounting, and overheads. Nova Scotia Power provides a breakdown of operating and maintenance costs for seven plant accounts and a further five customer expense accounts, which appear to provide an adequate degree of detail.

Q. What about the quality of input data?

A. Generally speaking, it is excellent.

Load data is actual down to the level of transmission terminals. Considerable effort has obviously been expended on estimating the coincidence factors for rural rate classes and the estimates agreed very respectably with transmission terminal data. Loss factors have been calculated with unusual care and attention to detail.

It is nevertheless suggested that NLH should give consideration to undertaking a load research program at some appropriate time in the future in order to avoid the necessity of relying on data from other utilities.

At present, rural classes are not rated in strict accordance with allocated cost, and accurate input data is unimportant. However, the situation could change in future.

Experience elsewhere indicates that hardware costs are high for a two-year acquisition program, but can be much lower with a more gradual approach.

Q. Do you have any comments on functionalization?

A. Yes. Functionalization is a fairly standard procedure, but one matter at issue between the parties at the last rate hearing should be discussed under this heading.

Consequent to the abolition of PDD's, and formation of separate rate classes for customers located therein, NLH no longer specifically assigned the cost of transmission supplying the said districts. NP contended that as a result it had to pay for its own dedicated transmission plus a large part of the cost of transmission dedicated to the supply of rural rate classes.

NLH rationalizes this change in the response to GCB-18, which states in part:

> "The basis for rationalizing this methodological change is the decision to separate the PDD into two or more separate rate classes."

So far as this rationalization is a plea of methodological necessity, it is insufficient. One recognized remedy in such a situation lies in proper functionalization. On this point the NARUC Cost Allocation Manual (1973) states: "By carefully choosing subfunctions within the main functions, the analyst attempts to assign costs within a function to groupings for which particular groups of customers are responsible."

However, the response to GCB-18 further points out that the proposed treatment "is consistent with a practice that will allocate cost to the Rural Rate Classes if a line is jointly used by NP and the Industrial class." This is a significant consideration. The change proposed by NLH certainly benefits the Rural Rate Classes at the expense of the remaining classes. However, the question which arises is whether the change erodes inter-class equity or whether in fact the pre-existing situation was unfair to the PDD's and the change improves equity.

A dependable answer to this question can only be obtained through detailed analysis. Designating the three concerned groups as R (for rural), N (for NP) and I (for industrial), the cost of lines or parts thereof in the following categories should be ascertained:

- R and N but not I.
- N and I but not R.
- I and R but not N.

In addition the analysis should determine the cost of lines or parts thereof serving each group individually but not specifically assigned under the NLH rule that lines connecting a generating station to the transmission system are treated as common cost.

From such an analysis it would become clear whether any of the three groups is significantly disadvantaged by the proposed treatment. Failing evidence of significant inequity, Hydro's proposed treatment should be approved. Otherwise a subfunction is required.

Q. Is the proposed classification of generation fixed cost appropriate?

A. There are two reasons for concern about the proposed classification. First, the evidence makes it clear that NLH is relying on the Average & Excess allocation method to provide a considerable part of the appropriate energy recognition. As previously noted in my testimony, that method provides no energy recognition whatsoever. Therefore, if the targeted degree of energy recognition is correct, the proposed classification is incorrect.

Secondly, the supporting evidence lacks the breadth one would expect in a generic hearing. Hydro plant was classified by the specific facilities approach. All thermal plant was classified to demand, with no stated justification except that Average & Excess allocation "gives substantial weight to energy" (Dr. Sarikas' testimony, page 10, lines 10 & 11).

Q. Is the specific facilities method a good analytical approach?

A. It is a recognized method. BC Hydro uses it. But if facility purposes are simply stereotyped (dams related to energy and turbines to capacity), the method leaves much to be desired.

The stereotyped relationships don't stand up to careful scrutiny. For example, one might consider the Bay D'Espoir plant. The installed capacity is 604 MW and the maximum capability 580 MW. Assuming gross spillage is avoided, the annual capacity factor of 51.9% implies that average flow would support an output level of 301 MW. Without a storage reservoir, firm capacity under low flow conditions would be less than 300 MW. So storage increases firm capacity. To the extent that dams increase head they increase both capacity and energy output. To the extent that they reduce spillage they increase energy. So the stereotype doesn't fit very well for dams.

Nor does it fit very well for turbines. They don't only supply capacity: they supply energy, too; in the case of NLH, about 70% of the system total.

For these reasons I have looked at other approaches to determining an appropriate classification.

Q. What approaches have you considered, and with what result?

A. Peaker and plant factor methods have been considered. Descriptions and results of applying these methods are set out in Appendix 2.

In summary, the results of applying such methods vary greatly depending on the unit cost of the proxy selected. Some methods (for example, the peaker credit method) select the unit capital cost of gas turbines as a proxy. Others (for example, the plant factor method) use as a proxy all load-following generation in the system.

The methods that use gas turbine capital costs classify to energy all the capital costs incurred in order to save fuel costs, but completely fail to take into account all the energy costs incurred in order to avoid excessive capital costs. They tend to classify an unrealistically high proportion of fixed cost to energy.

Methods that use all load-following plant as a proxy recognize the incurred energy costs, but tend to go too far, with the result that they typically tend to overestimate the demand component.

Q. What other approaches have you considered?

A. Classification on load factor, for one. This is a fairly common practice. It rests on the justification that a fraction of capacity equal to the system load factor is the absolute minimum necessary to meet the system energy requirement, and it classifies generation fixed cost accordingly.

Apart from recognized methods, helpful inferences can be drawn from the present state of the system.

Regarding Holyrood, some significance attaches to the fact that its capacity is fully utilized to meet system peaks, while its energy capability is used only to the extent of about 34.5/85 = 41%; the actual figure depending on hydro flows. This would support a classification of 1/1.41 = 71% to demand and 29% to energy. In any case, a 100% demand classification cannot be appropriate; if there had been no need to augment firm energy capability, NLH could have installed gas turbines instead of base load units at considerable cost savings.

It is certainly correct to classify peaking plant (gas turbines and diesels) 100% to demand.

The response to GCB-27 shows that demand insufficiency is expected to occur in 1993 and energy insufficiency in 1996. The relative importance of demand and energy in driving system expansion is a pertinent factor in classifying generation fixed cost. Assuming a 5.5% real discount rate, the three-year difference indicates that demand is about 17.4% more important than energy in this regard. This would justify an overall classification of 54% to demand and 46% to energy.

The relative effect of demand and energy on long-run cost is a further consideration. A peaker analysis outlined in Appendix 2, section 7, indicates about a 50/50 split between demand and energy responsibility.

The classifications resulting from these considerations are summarized in Exhibit GCB-4.

One further consideration is that NLH expects the system load factor to decrease. This means that demand is increasing faster than energy use, and might be regarded as warranting a slight biassing of classified cost toward demand.

Q. Should a single method of classification be used?

A. Not necessarily. In Manitoba, a single method (load factor) was selected and applied to all generation plant. In New Brunswick, after giving consideration to a number of methods, an arbitrary percentage within the range indicated by those methods was selected.

It would be entirely appropriate to use different methods for different types of generation, as NLH proposes to do.

In my opinion, use of an analytical basis is slightly better than selection of a fixed percentage. If based on analytical methods classification will adjust to system changes, while a fixed percentage will drift out of step.

Q. What choice do you favour?

A. I am too impressed with the flaws in every method of analysis to believe that one can find a single, provably correct solution, so my opinion can best be stated in terms of a probability curve. On all the evidence available, I believe that the probability of accurately reflecting cost responsibility is highest in the area of 45 to 50% classification to demand and decreases fairly rapidly for higher or lower figures.

The combination of load factor classification of hydro and peaker credit classification of thermal generation falls in this range and would provide a recognized methodological basis.

Q. Should the same classification be applied to the Labrador Interconnected and Isolated Rural systems?

A. Not automatically. These systems are physically separate and have their own sources of power supply, which are different than those of the Island Interconnected system. NLH has made separate cost of service studies for them. The classification used should reflect the characteristics of the system in each case.

Where power supplies are purchased, the respective costs of demand and energy should be used if specified in the purchase agreement. Otherwise, a proxy or load factor approach would probably be appropriate.

Q. NLH proposes to classify transmission 100% to demand. Do you consider that would be appropriate?

A. The figure appears to be too high.

The arguments given by Dr. Sarikas at page 13, lines 1-17 of his testimony supporting the proposed classification provide a meticulously correct description of the factors which affect transmission line cost. However, this is only one aspect of the matter. It is also relevant to ask why the transmission lines were built, and what role they play in the system.

It may be instructive to review some recent utility reasoning on this subject.

Manitoba Hydro concluded that its bulk power system transmission was built for the purpose of bringing the output of its remote hydro generation to system load centers, that such transmission was therefore an inherent part of the cost of tapping the least-cost sources of generation and should therefore be classified the same way as the generation it was built to serve.

New Brunswick Power reasoned that its generation was at or close to load centers and that the role of its transmission system was to accommodate peak demands. It therefore proposed a 100% demand classification on much the same grounds as cited by Dr. Sarikas.

In both these cases, regulatory acceptance ensued.

Recently, NS Power filed a report on cost of service matters in which it recommended a 100% energy classification for lines built to serve its minemouth thermal plants, and 100% demand classification for all other lines. The plants were built at minemouth instead of load center for one reason: transmission was cheaper than fuel transportation. This has not yet received regulatory consideration.

The point is that in all the above cases, the criterion was, "Why did we make these investments?".

GCB-11 and -12 provide some information on causation in the NLH system. It appears that of the total investment in transmission lines, some $81.6 millions were spent at least partly to connect new generating capacity to the system, about $45.7 millions were spent at least partly to connect previously isolated areas and about $91.8 millions were spent entirely for the purpose of meeting capacity, stability or voltage requirements.

It would be appropriate, in my opinion, to classify lines built and still used primarily to connect generation to the system on the same basis as the generation, and to classify lines built to meet capacity requirements or other planning criteria completely to demand.

In the case of lines built to connect previously isolated systems, and not specifically assigned, where the justification was to avoid the high fuel cost of local generation, a considerable share of the cost would appropriately be classified to energy.

If this type of analysis were applied, the demand component of NLH transmission would probably be quite large, but certainly not 100%.

In summary, the filed evidence indicates lack of sufficient depth in the analysis. It is recommended that the Board require a review and report based on the foregoing considerations before making a decision on the classification of transmission cost.

Q. How are distribution costs usually classified?

A. Some distribution costs correlate with the number of customers served. To reflect this, it is normal to classify service and meters entirely as customer cost. In addition, poles, wire and sometimes distribution transformers are classified partly as customer cost. All other distribution plant, if not specifically assigned, is normally classified to demand.

Q. Where costs are split between demand and customer, how are the proportions determined?

A. Among recognized methods, the main alternatives are the zero intercept and minimum system methods. The zero intercept method is inaccurate by reason of the fact that it only classifies the marginal cost of demand as demand cost and classifies all other cost as customer cost. The minimum system method is even worse; it only classifies a part of the marginal cost of demand to demand. For this reason, the proportion of customer cost is usually overstated where recognized analytical approaches are used, typically varying between about 45% and 70%. For such reasons some utilities prefer to split costs on a judgmental basis.

Q. What are your comments on NLH's analysis?

A. NLH has included transformers in the costs split between the two classifications and has used the zero intercept method to determine the demand component. The NLH analysis results in a customer component of about 23.5% of plant cost. This is in my opinion a realistic figure, but the method of determination gives cause for concern.

RAB-1, Schedule 4.3, shows the calculation for distribution transformers. By plotting the cost of various transformer sizes, it is inferred that a transformer of zero capacity would cost $1,460.93. This figure of course includes the cost of protection, insulation and oil, all mediated by the primary voltage to which the transformer is connected. The oil necessitates a tank to hold it; the tank is heavy and requires substantial mounting brackets; the weight adds to installation cost.

A whole series of costs included in the customer component is thus seen to derive from the primary voltage at which the transformer operates. But this voltage is a consequence of the demand placed on the distribution system. It is not customer related. This example exposes the inherent error in a method which only charges the marginal demand cost to demand and charges all other demand costs as well as all customer costs to customers.

Indeed, one can and should go even further. If the demand of every customer were zero or close to it, most feeders could operate satisfactorily at 240 volts and very few line transformers would be required. For this reason, a large part of transformer cost should be classified to demand and in fact some utilities charge 100% to demand.

The other concern arises from the method used to determine the demand/customer split for poles, also shown in RAB-1, Schedule 4.3. The regression in this case is carried out in terms of pole length, from which it is concluded that a pole of zero length would cost \$47.03. This determines the customer portion of pole investment.

The calculations are no doubt correct, but a pole of zero length is not a good proxy for customer cost. Generally speaking, pole line length increases as the number of customers increases and the poles which have to be set for such line extensions would not be poles of zero length even if all the additional customers had zero demands. Minimum pole heights would be dictated by Electrical Code and highway clearance requirements.

But under conditions of zero demand, voltages would be lower, clearances would be reduced, pole lengths and diameter would be reduced, compared to the poles actually in service.

From a common sense point of view, it appears that the analysis grossly overstates the appropriate percentage of customer cost for transformers; modestly understates the appropriate percentage for poles; and probably gives a reasonable bottom line result.

Q. Do you have any recommendation?

A. The split of distribution assets does not exert much leverage on the inter-class sharing of costs and on this basis it would be reasonable for the Board to accept the results of the NLH analysis.

However, if the Board deemed it desirable to improve the analytical basis for this part of the cost of service, it could direct NLH to undertake further analysis.

Q. What kind of analysis would be appropriate?

A. In my opinion, the following approach would be appropriate:

1. Classify to demand all lines between substations and the load center of each community served by NLH. The cost of these lines depends on the demand and not on the number of customers served.

2. Classify all transformers to demand.

3. Determine the cost per pole-line mile for a line suitable for zero demand conditions. Conductors in such a line would be guy strand or copperweld, operating at 240 volts. Poles would be of minimum size and maximum spacing consistent with design requirements.

4. Determine the actual cost per pole-line mile for lines not included in step 1 above and escalate this cost to present-day levels.

5. The ratio of the costs determined in 3 above to the cost determined in 4 above would then be a reasonable estimate of the customer component of cost for poles and wire not included in 1 above.

Q. Do you consider the Average & Excess method of allocation appropriate for generation demand costs?

A. Yes. It has been judged acceptable in the past and in the absence of any demonstrated reason for change, it should be retained.

Q. Do you agree with the rationale given by Dr. Sarikas for using the Average & Excess method to allocate generation demand costs and the Coincident Peak method for transmission?

A. To the extent that Dr. Sarikas' arguments rest on the assumption that the Average & Excess method provides a measure of energy recognition, I disagree.

The difference between the two methods relates only to the user-pay and diversity benefit characteristics of the Average & Excess method. Thus choice boils down to a simple question: whether there should be a charge for off-peak use of the transmission system as well as for off-peak use of the generation system.

Q. What do you recommend?

A. There is comparatively little diversity in the Island Interconnected system, so the charge for off-peak demand applied by the Average & Excess method is quite high. The CP method does not make any charge for off-peak kilowatts, so use of the CP method for transmission would limit the overall charge.

For this reason, the NLH proposal is in my opinion appropriate for the Island Interconnected system.

Q. Does the same consideration apply to the Labrador Interconnected and Rural Isolated systems?

A. No. The diversity is much higher in these systems. Also, transmission costs are relatively minor in the Rural Isolated system.

If the Average & Excess method is considered appropriate for allocation of generation demand costs in these systems, there does not appear to be any reason for allocating transmission demand costs on a different basis.

Q. Is the proposed method of allocating the rural revenue deficiency appropriate?

A. NLH proposes to allocate the rural revenue deficiency to the subsidizing classes on the basis of revenue requirement.

This scheme would result in Labrador Interconnected System paying about 6% of the deficiency and Island subsidizing classes paying about 94%. The cost of electricity in the Labrador Interconnected System is less than half as much as in the Island Interconnected System. For this reason, the subsidy costs would be about $4.71 per MWh at generation for the Island classes and about $1.94 per MWh for the Labrador classes. To saddle certain classes with higher subsidy costs simply because they have higher rates to start with seems unfair.

Q. Does Hydro's approach apply standard cost of service methodology?

A. Proration on cost between classes within the same class of service is standard procedure. It is used many times in a typical cost of service study. However, in this case separate cost of service studies have been made for Island Interconnected, Labrador Interconnected and Isolated Systems. Thus, the classes to which deficit costs must be allocated do not share a common cost base. In consequence, the considerations which usually justify proration on cost are simply non-existent insofar as the sharing of costs between Labrador and Island Interconnected Systems is concerned.

Q. What alternative approaches might be preferable?

A. I am not aware of any generally accepted cost of service methodology for dealing with this particular situation. In finding the best solution, judgment must play a part.

It may be helpful to consider the circumstances which give rise to the revenue deficiency. To the best of my knowledge, statutory and, for the present time at least, public policy limitations exist on Rural and Isolated rate levels. Newfoundland Light & Power rates provide a ceiling. One might draw the inference that public policy at this time requires those who are fortunate enough to enjoy cheap electric service to share their good fortune with those who are not so lucky.

From a purely tactical point of view, charging as much of the deficiency as possible to the Island Interconnected subsidizing classes in general and to Newfoundland Light & Power in particular would maximize the increase in the aforesaid ceiling and minimize the apparent revenue deficiency.

However, such an approach would increase the rate differential between Labrador and Island Interconnected Systems and would seem in this respect to circumvent rather than support public policy; if indeed that policy favours a levelling process.

From the point of view of equitability, there can be little doubt that the deficiency should be shared between Island and Labrador subsidizing classes on the basis of equal per unit costs.

Q. How can this be achieved?

A. From Dr. Sarikas' arguments (page 22 of his testimony), it seems clear that any method of allocating the deficiency must observe the following constraints:

(1) Subsidizing classes within any one cost of service area should have identical revenue-to-cost ratios after the allocation. This dictates proration on cost within each cost of service study.

(2) The quantity measure used as the basis for allocation cannot be energy only; it must be inclusive of all aspects of electric service.

These requirements are easily met. One approach which does so involves a preliminary split of costs between Newfoundland and Labrador on the basis of demand, energy and customer number. It is illustrated in Exhibit GCB-5.

The procedure illustrated first classifies the deficit by proration on the classified costs of subsidizing classes. Next, the classified totals are divided by the use characteristics of the subsidizing classes as a whole to obtain unit classified costs. These unit costs are then used to allocate between Island and Labrador Systems.

This is nothing more than a mini-cost of service study for the purpose of allocating the deficit between the two systems. After that procedure, the costs assigned to each system should be allocated to subsidizing classes within that system in the manner proposed by Dr. Sarikas.

The result of this approach is to increase unit costs equally in the two Interconnected Systems. However, the percentage increase would be over twice as large for Labrador as for the Island. It might for that reason be found expedient to spread the Labrador impact over two or more successive rate increases. That, however, is an aspect of rate design rather than cost of service methodology.

Q. Does Newfoundland Light & Power receive credit for the capacity of its mobile gas turbine?

A. The response to GCB-13 indicates that no credit is provided in the present cost of service study.

Q. This was a point of disagreement at the last hearing. What are your views?

A. From the record of that hearing it appears that NP claimed in final argument that it should receive a credit and that Hydro disagreed in its rebuttal on the grounds that:

(1) The purpose of the unit is not for system reserve, but to provide emergency generation for areas that become isolated from the main grid;

(2) That it is not permanently connected to the grid; and

(3) That no credit had been given in the past and NP had not objected.

Hydro's first point raises the question whether the purpose for which a generating unit exists is a proper criterion for deciding if the unit should or should not be included as part of system generating capacity, or whether the criterion should be the unit's availability and therefore its influence on loss of load expectancy. The latter view seems more logical.

Relative to Hydro's second point, Mr. Evans testified that the unit is connected to the system except for disconnection of "about a day" on the relatively rare occasions when it is being moved to meet a "disaster-type" situation elsewhere. If this is correct, the unavailability due to its mobile role is of the same order as that of other generating plant which Hydro does include in its system generating capacity and exclusion would not be justified on the grounds of no permanent connection.

Regarding the third point, Mr. Evans' testimony was that in prior years, NP received full credit for its hydro capacity and the mobile gas turbine and diesels were regarded as reserve for such hydro capacity. It would therefore appear that the mobile gas turbine was in fact regarded in prior years as part of the system capacity, albeit in a reserve role, and NP had, at that time, no reason for complaint.

Unless there are other considerations not included in the record of the preceding hearing, it would in my opinion be proper to include the mobile gas turbine capacity as part of NP's gross generation before adjusting for reserve capacity.

NON-COINCIDENT PEAK

	NCD METHOD	A & E METHOD	CP METHOD
NON-COINC. EXCESS DEMAND	COST/KW = \$S/CD D.B./KW = $\frac{\$S(D-1)}{CD}$	COST/KW = $\frac{\$S(1-F)}{C(D-F)}$ D.B./KW = $\frac{\$S(D-1)}{C(D-F)}$	COST/KW = 0 D.B./KW = \$S/C
COINCIDENT PEAK			
COINCIDENT EXCESS DEMAND	COST/KW = \$S/CD D.B./KW = $\frac{\$S(D-1)}{CD}$	COST/KW = $\frac{\$S(1-F)}{C(D-F)}$ D.B./KW = $\frac{\$S(D-1)}{C(D-F)}$	COST/KW = \$S/C D.B./KW = 0
AVERAGE DEMAND	COST/KW = \$S/CD D.B./KW = $\frac{\$S(D-1)}{CD}$	COST/KW = \$S/C D.B./KW = 0	COST/KW = \$S/C D.B./KW = 0

The comparative unit costs and diversity benefits (D.B.) resulting from allocation by the Non-Coincident Demand, Average and Excess, and Coincident Peak demand methods are illustrated in this Exhibit. Costs and benefits are stated in terms of the allocated demand cost \$S; the coincident peak demand in Kilowatts C; the system diversity factor D and the system load factor F.

EXHIBIT GCB-2.1

NEWFOUNDLAND & LABRADOR HYDRO SYSTEM DATA

(SOURCE: GCB-25)

CLASS	(1) COINCIDENT PEAK DEMAND KW	(2) NON-COINC. MAXIMUM DEMAND KW	(3) DIVERSITY FACTOR d	(4) ENERGY AT SYSTEM MWh	(5) LOAD FACTOR f	(6) AVERAGE DEMAND KW	(7) EXCESS DEMAND KW
1. Newfoundland Light & Power	1,004,786	1,017,522	1.01268	4,397,884	.49965	502,042	515,480
2. Industrial	153,664	168,722	1.09799	1,292,104	.95989	147,500	21,222
RURAL							
3. Domestic	21,186	23,316	1.10054	93,097	.50163	10,628	12,688
4. Domestic All Electric	32,496	34,529	1.06256	115,367	.40527	13,170	21,359
5. Special	83	92	1.10843	293	.40298	33	59
6. General Service 0-10	2,987	4,496	1.50519	14,660	.56027	1,673	2,823
7. General Service 10-100	8,397	12,101	1.44111	49,001	.66616	5,594	6,507
8. General Service 110-1000	3,070	6,479	2.11042	26,027	.96779	2,971	3,508
9. General Service Over 1000	2,027	7,934	3.91416	7,830	.44096	894	7,040
10. General Service AE 0-10	143	270	1.88811	688	.54922	79	191
11. Street Lighting	865	834	0.96416	3,540	.46718	404	430
12. Total, Rural	71,254	90,051	1.26380	310,503	.49745	35,446	54,605
13. Total, System	1,229,704	1,276,295	1.03789	6,000,491	.55703	684,988	591,307

EXHIBIT GCB-2.2

ALLOCATION OF $1000 FIXED GENERATION COST TO NLH CLASSES BY VARIOUS METHODS

CLASS	(1) CP METHOD $1000 DEMAND $ 0 ENERGY	(2) CP METHOD $442.97 D $557.03 E	(3) CHANGE DUE TO ENERGY CLASSI-FICATION	(4) A & E METHOD	(5) CHANGE FROM CP METHOD ($1000 D)	(6) CHANGE FROM CP METHOD WITH ENERGY ALLOCATION
	$	$	%	$	%	%
1. Newfoundland Light & Power	817.10	770.21	-5.74	794.43	-2.77	3.15
2. Industrial	124.96	175.30	40.29	135.84	8.71	-22.51
RURAL						
3. Domestic	17.23	16.27	-5.54	18.15	5.34	11.52
4. Domestic All Electric	26.42	22.42	-15.18	26.71	1.10	19.19
5. Special	.07	.06	-15.41	.07	5.28	24.46
6. General Service 0-10	2.43	2.44	0.32	3.48	43.08	42.62
7. General Service 10-100	6.83	7.57	10.91	9.42	38.01	24.43
8. General Service 110-1000	2.49	3.52	41.08	5.04	102.04	43.21
9. General Service Over 1000	1.65	1.45	-11.61	6.00	264.06	311.88
10. General Service AE 0-10	.12	.12	-0.78	.21	78.26	79.66
11. Street Lighting	.70	.64	-8.98	.65	-7.50	1.63
12. Total, Rural	57.94	54.49	-5.96	69.73	20.34	27.97
13. Total, System	1,000.00	1,000.00	0.00	1,000.00	0.00	0.00
14. Allocated energy cost	0.00	557.03		0.00		

EXHIBIT GCB-3

PLANT FACTOR METHOD

ADAPTED TO NLH GENERATION

1. DATA:

System capacity, MW	1,506.5 (b)
Annual energy, GWh	6,000.491
Minimum load, approximate, MW	367 (a)
Hydraulic generation capacity factor	.5403 (b)
Holyrood capacity factor	.345
Gas turbine & diesel capacity factors, less than:	.01

   (a) Based on minimum for typical summer day.

   (b) Based on total unit capacities.

2. Base load capacity
   Because hydraulic generation performs both base load and load-following functions, the usual step of identifying units belonging in each category is dispensed with and the base load capacity component is taken at .95 availability to be (367/.95) MW = 386.3

3. Base load generation = (.367 x 8760) GWh = 3,214.92

4. Load-following plant characteristics
   Load following capacity = (1,506.5 - 386.3) MW = 1,120.2
   Load following energy = (6,000.491 - 3,214.92) GWh = 2,785.571
   Capacity factor of load following generation:
   2,785.571/1.1202 x 8760 = .2838

5. Classification of hydraulic generation costs
   Energy component = (.5403 - .2838)/.5403 = .475
   Demand component = 1 - .475 = .525

   (The usual unit-by-unit classification would give slightly different results.)

6. Classification of Holyrood unit costs
   Energy component = (.345 - .2838)/.345 = .177
   Demand component = 1 - .177 = .823

7. Classification of gas turbines & diesel costs
   The capacity factors of these units being less than .2838, the costs are classified 100% to demand.

ISLAND INTERCONNECTED SYSTEM

CLASSIFICATION OF GENERATION FIXED COST

BY VARIOUS MEANS

ANALYTICAL BASIS OR RATIONALE	(1) HYDRO PLANTS		(2) HOLYROOD		(3) PEAKING PLANTS		(4) SYSTEM* OVERALL	
	DEMAND %	ENERGY %	DEMAND %	ENERGY %	DEMAND %	ENERGY %	DEMAND %	ENERGY %
1. Specific facilities (NLH)	56.4	43.6	100	0	100	0	69.3	30.7
2. Peaker Proxy, 50 MW unit	56.3	43.7	100	0	100	0	69.3	30.7
3. Peaker Proxy, 95 MW unit	43.0	57.0	100	0	100	0	59.9	40.1
4. Peaker credit	18.5	81.5	50	50	100	0	29.1	70.9
5. Plant factor	52.5	47.5	82.3	17.7	100	0	61.8	38.2
6. System load factor	44.3	55.7	44.3	55.7	44.3	55.7	44.3	55.7
7. Utilization of capability	50	50	71	29	100	0	57	43
8. System expansion responsibility	--	--	--	--	--	--	54	46
9. Long-run costs	--	--	--	--	--	--	50	50
COMBINATIONS OF ABOVE: (HYDRO & OTHER)								
10. Plant factor & peak credit	52.5	47.5	50	50	100	0	53.0	47.0
11. Load factor & peak credit	44.3	55.7	50	50	100	0	47.2	52.8

*Where system overall percentages are calculated, the overall percentages are shown for direct fixed annual cost only. Overheads and miscellaneous costs and credits are excluded.

EXHIBIT GCB-5.1

1.

CLASSIFICATION OF DEFICIT

	(Classified Allocated Costs Before Deficit Allocation				
CLASS	(1) TOTAL $	(2) DEMAND $	(3) ENERGY $	(4) CUSTOMER $	SOURCE (RAB-1 Schedule)
1. NLP	175,286,264	114,823,391	58,218,885	2,243,988	1.3.1(P1)
2. Island Industrial	37,164,834	19,091,933	17,104,784	968,117	1.3.1(P1)
3. Lab. Intercon.	13,401,357	10,470,416	1,408,487	1,522,454	1.3.1(P3)
4. Total	225,852,455	144,385,740	76,732,156	4,734,559	
5. Deficit prorated	28,487,316	18,211,723	9,678,412	597,181	Prorated on li 4

2.

UNIT COSTS OF DEFICIT

	(Demand, Energy & Customer Totals)			
CLASS	DEMAND AED KW	ENERGY MWh	CUSTOMER* Equivalent Unweighted	
6. NLP	977,031	4,397,884	9,574	3.1A & 3.2A
7. Island Industrial	166,911	1,292,104	4,131	3.1A & 3.2A
8. Subtotal, Island	1,143,942	5,689,988	13,705	
9. DND	21,236	141,298	484	3.1C & 3.2C
10. IOCC	38,409	243,051	--	3.1C
11. Labrador Rural	111,624	485,366	7,560	3.1C & 3.2C
12. Subtotal, Labrador	171,269	869,715	8,044	
13. Total	1,315,211	6,559,703	21,749	
14. Deficit unit costs	13.84700/KW	$1.47543/MWh	$27.458 /cust.	Li 5/li 13

*Specifically assigned costs are converted to equivalent unweighted customers by dividing the assigned cost by the allocated customer cost per unweighted customer ($234.38 Island & $189.28 Labrador).

3. ALLOCATION OF DEFICIT

	ISLAND $	LABRADOR $
Demand cost		
$13.847/KW x 1,143,942 KW	15,840,162	
x 171,269 KW		2,371,561
Energy		
$1.47543 x 5,689,988	8,395,204	
x 869,715		1,283,208
Customer		
$27.458 x 13,705	376,310	
x 8,044		220,871
ALLOCATED TOTALS:	24,611,676	3,875,640

Notes:

1. Unit costs are taken from GCB-5.1, line 14. Quantities are taken from GCB-5.1, line 8 for Island and line 12 for Labrador.

2. The allocated totals should be prorated on allocated costs of the subsidizing classes within each cost of service.

AN ANALYSIS OF CERTAIN FEATURES OF THE AVERAGE AND EXCESS METHOD OF DEMAND COST ALLOCATION

1. Average & Excess versus Coincident Peak Allocation

1.1 The difference in allocated cost between Average & Excess allocation using non-coincident demands and Coincident Peak allocation is here derived as a function of load factor and diversity factor.

1.2 The following case is assumed:

- Demand costs of \$S are to be allocated.
- There are k customer classes, designated a to k respectively. Without loss of generality only class i is considered.
- Symbols used to denote relevant class and system data are as follows:

Total of class non-coincident demands	=	N
System coincident peak demand	=	C
System energy	=	E
System diversity factor	=	D
System load factor on coincident peak demand	=	F
Non-coincident demand of class i	=	n
Coincident peak demand of class i	=	c
Class i energy use	=	e
Diversity factor of class i	=	d
Load factor of class i calculated on system peak demand	=	f
Hours in a year	=	8760

1.3 The allocated cost to class i is by definition:

$$\frac{\$S(1-F)(\text{Class } i \text{ excess demand})}{(\text{System excess demand})} + \frac{\$SF(\text{Class } i \text{ average demand})}{(\text{System average demand})}$$

$$= \frac{\$S(1-F)(n - e/8760)}{(N - E/8760)} + \frac{\$SF(e/8760)}{(E/8760)} \text{ ------ } (1)$$

By definition,

$$D = N/C \text{ or } N = CD \text{ --------------- } (2)$$

$$d = n/c \text{ or } n = cd \text{ --------------- } (3)$$

$$F = E/8760C \text{ or } E/8760 = FC \text{ ----------- } (4)$$

$$f = e/8760c \text{ or } e/8760 = fc \text{ ----------- } (5)$$

Substituting (2), (3), (4) and (5) in (1) gives:

$$\text{Allocated cost} = \frac{\$S(1-F)(cd - fc)}{(CD - FC)} + \frac{\$SFfc}{FC}$$

$$= \frac{\$Sc(1-F)(d - f)}{C \quad (D - F)} + \frac{\$Sfc}{C}$$

$$= \frac{\$Sc}{C}\left[\frac{(1-F)(d - f)}{D - F} + f\right]$$

$$= \frac{\$Sc}{C}\left[\frac{d - Fd - f + Ff + Df - Ff}{D - F}\right]$$

$$= \frac{\$Sc}{C}\left[\frac{d - Fd - f + Df}{D - F}\right]$$

$$= \frac{\$Sc}{C}\left[\frac{(1-F)d + (D-1)f}{D - F}\right]$$

$$= \text{CP allocation}\left[\frac{(1-F)d + (D-1)f}{D - F}\right] \text{ -------- } (6)$$

and similarly for all other classes.

2. <u>Calculation of the unit demand costs resulting from Average & Excess Allocation</u>

2.1 Class demands are segregated into three categories for purposes of analysis.

1. Kilowatts of average demand.
2. Kilowatts of on-peak excess demand.
3. Kilowatts of off-peak excess demand.

2.2 Using the system data and symbols defined in 1.2 above, average demand cost is allocated as:

$$\frac{\$SF\ (\text{class average demand})}{(\text{system average demand})}$$

$$= \frac{\$SF(fc)}{FC} = \frac{\$S(fc)}{C}$$

The unit demand cost is therefore $\frac{\$S}{C}\frac{fc}{fc} = \frac{\$S}{C}$ - - - - - - - - - (7)

2.3 Excess demand cost is allocated by the A & E method as

$$\frac{\$S(1-F)\ (\text{class excess demand})}{(\text{system excess demand})}$$

$$= \frac{\$S(1-F)(n - e/8760)}{(N - E/8760)}$$

Substituting equations (2), (3), (4) and (5), this becomes

$$\frac{\$S(1-F)(cd - fc)}{CD - FC}$$

$$= \frac{\$Sc}{C}\ (1-F)\ \frac{(d - f)}{(D - F)}$$

The quantity of excess demand is n - fc = (d - f)c KW.

The unit allocated cost is therefore $\frac{\$S}{C}\frac{(1 - F)}{(D - F)}$ - - - - - - - - (8)

The diversity benefit, per KW of coincident excess demand, is then

$$\frac{\$S}{C} - \frac{\$S}{C}\frac{(1 - F)}{(D - F)} = \frac{\$S}{C}\frac{(D - 1)}{(D - F)} \quad \text{- - - - - - - - (9)}$$

3. <u>The Average & Excess method as a means of reflecting energy responsibility for generation fixed cost</u>

3.1 The effect of applying the Average and Excess method to generation fixed cost is here compared to the effect of classifying a portion of fixed costs to energy before applying the coincident peak method.

3.2 The first case assumed is allocation of all costs as demand costs by the CP method. The allocation to class i is:

$$\frac{\$S\ (\text{class CP demand})}{(\text{system CP demand})}$$

$$= \frac{\$Sc}{C} \text{ - - - - - - - - - - - - - - - - } (10)$$

3.3 Next it is assumed that a portion of fixed cost $SF is classified as energy-related and the balance $S(1 - F) is classified as demand-related. Again, the allocation is made by the CP method. The allocation of demand costs to class i is $S(1 - F)(c/C) and the allocated energy cost is $SF(e/E). The total allocation to class i is therefore

$$\$S\ \left[(1 - F)\ c/C + F\ e/E\right] \text{ - - - - - - - - - - } (11)$$

From equations (4) and (5), we have:

$$FC = 8760\ E, \text{ and}$$

$$fc = 8760\ e.$$

Substituting these in (11) gives:

$$\text{Allocation to class i} = \$S\left[\frac{(1 - F)\ c}{C} + \frac{Ff\ c\ 8760)}{8760\ F\ C}\right]$$

$$= \$S(c/C)(1 + f - F) \text{ - - - - - - - - - - } (12)$$

3.4 Comparing equations (10) and (12), it is evident that the incremental cost allocated to class i as a result of classifying a fraction F of generation fixed cost to energy varies directly as the difference between class and system load factor. For example, if the class load factor is 10% less than the system load factor, the allocated cost will decrease by 10% due to the classification of $SF to energy.

3.5 The demand/energy classification on load factor assumed in 3.3 above was chosen because that is the apparent split applied in the A & E method. If instead a fraction x of the generation fixed cost is classified to energy, then repetition of the argument used in 3.3 above results in an allocation to class i of:

$$\$S(c/C)(1 + (x/F)(f - F)) \text{ - - - - - - - - - - - - } (13)$$

The effect of classification to energy is still proportional to (f - F) but also proportional to the magnitude of x.

3.6 It is now assumed that the \$S is allocated using the A & E method. From equations (6) and (10) we have

$$\text{Allocation to class i} = \frac{\$Sc}{C}\left[\frac{(1 - F)d + (D - 1)f}{D - F}\right] \text{ - - - - - - } (14)$$

It is at once evident that the effect of A & E allocation involves class and system diversity factors as well as load factors and therefore cannot reflect energy responsibility for generation fixed cost in exactly the same way as an initial classification to energy does.

3.7 To determine what recognition the A & E method gives to energy, the following identity is available:

The A & E allocated cost equals the CP allocation, plus the user-pay charges levied on NC excess KW, less the diversity benefit awarded to coincident excess KW, plus the amount levied as energy recognition. Using the symbols p, q, r, s and t respectively for these quantities:

$$p = q + r - s + t, \text{ or}$$

$$t = p - q - r + s.$$

Evaluating these quantities:

p, the A & E allocation, is given by equation (14).

q, the CP allocation, is \$Sc/C.

r, the user-pay charge, is the cost per NC excess KW multiplied by the number of kilowatts:

$$\frac{\$S\ (1 - F)\ (n - c)}{C\ (D - F)}$$

$$r = \frac{\$Sc\ (1 - F)\ (d - 1)}{C\ \ (D - F)}$$

s, the diversity benefit, is the benefit per KW multiplied by the number of kilowatts:

$$s = \frac{\$Sc}{C}\frac{(D - 1)(1 - f)}{(D - F)}$$

Therefore:

$$t = \frac{\$Sc}{C}\frac{(1-F)d + (D-1)f}{(D - F)} - \frac{\$Sc}{C} - \frac{\$Sc(1-F)(d-1)}{C\quad(D-F)} + \frac{\$Sc(D-1)(1-f)}{C\quad(D-F)}$$

$$= \frac{\$Sc}{C}\left[\frac{(1-F)d + (D-1)f + (D-1)(1-f) - (1-F)(d-1)}{(D - F)} - 1\right] \quad *$$

which reduces to:

$$t = 0.$$

The energy recognition provided by the A & E method is therefore precisely zero for class i, and in consequence zero for all classes.

This result could be demonstrated in a number of ways. For example, it has been shown that the A & E costs allocated on energy use, which are purported to account for the energy recognition, in fact determine the cost of average demand. The resulting per KW cost of average demand is \$Sc/C, which is exactly the same as the unit cost provided by the CP method without any classification to energy. One must conclude that if the part of the allocation which purports to provide energy recognition does not do so, then no such recognition exists.

*This line corrected.

APPENDIX 2

PEAKER AND PLANT FACTOR

METHODS OF CLASSIFICATION

1. The Rationale for Peaker Analysis

In the usual case, gas turbines provide capacity at least capital cost but incur higher fuel cost than other types of thermal generation. Thus where loads with little associated energy must be served, gas turbines are the least cost source. However, where the associated energy is significant, base load generation is selected because the savings in fuel costs outweigh the extra capital costs.

Under such circumstances the capital cost of a gas turbine is a proxy for the capacity portion of the capital cost of any generating station. Any excess investment is attributable to the requirement for energy output.

While peak loads are often served by gas turbines, other types of generation may perform this function. In consequence, the proxy for capacity is in most methods broadened to include any type of peaking plant.

2. Peaker Methods

In order to remove cost differences due to inflation, book costs are restated in current dollars for purposes of analysis. Unit costs are calculated as restated book cost divided by net capacity.

For each plant, the capacity fraction of capital cost is the unit peaker cost divided by the unit cost of the plant in question. The energy fraction is 1 minus the capacity fraction. The fractions (or percentages) thus obtained are used to apportion annual fixed costs between demand and energy classifications.

Individual methods differ only in the selection of the peaker proxy. Terminology is by no means standardized, but various methods are here designated as follows:

- The Peaker Proxy method uses a new gas turbine as proxy.

- The Peaker Credit method uses all existing peaking units in the system as the proxy.

- The Composite Peaker method uses all load-following plant in the system as the proxy.

3. The Peaker Proxy Method

The response to GCB-4 gives the planning cost of a new 50 MW gas turbine as $932.90/KW plus escalation from 1990, plus IDC. Because this unit size appears small, a 95 MW unit is also used as the proxy. In 1991 dollars an installed cost of $1,031/KW is estimated for the 50 MW size and an installed cost of $780/KW for the 95 MW size. The method of estimating the cost of the larger unit is set out in 7 below.

Using capital costs from NP-35, the method is applied to NLH generation in Table 1 below.

TABLE 1

CLASSIFICATION BY PEAKER PROXY METHOD

	PLANT	(1) CAPITAL COST $(1991) x 1000	(2) CAPACITY KW	(3) UNIT COST $/KW	(4) CAPACITY (50 MW PROXY) %	(5) PORTION (95 MW PROXY) %
1.	Holyrood GT	7,843	10,000	784.3	100	99
2.	Stephenville GT	15,703	54,000	290.8	100	100
3.	Hardwoods GT	15,703	54,000	290.8	100	100
4.	Hawkes Bay D	2,052	5,000	410.4	100	100
5.	TOTAL PEAKING	41,301	123,000	335.8	100	100
6.	Holyrood	318,815	475,100	671.0	100	100
7.	Bay D'Espoir	590,906	580,000	1,018.8	100	77
8.	Snooks Arm	203	600	338.3	100	100
9.	Venams Bight	203	400	507.5	100	100
10.	Hinds Lake	130,575	75,000	1,741.0	59	45
11.	Upper Salmon	206,042	84,000	2,453.0	42	32
12.	Cat Arm	319,761	127,000	2,518.0	41	31
13.	Paradise River	21,954	8,000	2,744.0	38	28
14.	TOTAL HYDRO	1,269,644	899,000	1,412.3	56.3	43.0

In peaker and plant factor methods, it is usual to apply the demand and energy percentages derived for each plant to the fixed annual costs relating to that plant. The totals of demand and energy costs so calculated then yield the overall percentage split. This procedure is followed here, except that only O & M, depreciation, interest and margin costs are considered. Overheads and miscellaneous costs and credits are omitted because some could be preferentially chargeable to certain plants or certain types of generation.

4. The Peaker Credit Method

The peaker credit method is applied in Table 2. Unit plant costs from Table 1 are used. The unit cost of peaking plant is $335.8/KW, as calculated in Table 1, line 5.

TABLE 2

CLASSIFICATION BY PEAKER CREDIT METHOD

	PLANT	(1) UNIT COST $/KW	(2) DEMAND %	(3) ENERGY %
1.	Peaking	335.8	100	0
2.	Holyrood	671.0	50.0	50
	HYDRO			
3.	Bay D'Espoir	1,018.8	33.0	67.0
4.	Snooks Arm	338.3	100.0	0
5.	Venams Bight	507.5	66.2	33.8
6.	Hinds Lake	1,741	19.3	80.7
7.	Upper Salmon	2,453	13.7	86.3
8.	Cat Arm	2,518	13.3	86.7
9.	Paradise River	2,744	12.2	87.8
10.	TOTAL HYDRO	1,412.3	18.5	81.5

5. The Composite Peaker Method

This method requires the separation of load following and base load plants. It appears that the hydro plants as a group are load following, as well as Holyrood and the peaking units. Separation may be possible if some logical basis of assigning some hydro units to the base load category can be found, but the writer is not aware of any such basis. A purely arbitrary separation would simply result in an arbitrary classification of cost and in the absence of any separation, costs would simply be classified 100% to demand. It therefore appears likely that this method is inapplicable to the NLH system.

6. Comment on Peaker Methods

It is evident that results are very sensitive to the definition of the proxy and the resulting unit cost attributed to capacity. There is no certainty that the unit cost as defined by any of the methods here considered is really representative of the cost of pure capacity from a planning perspective at the time when any hydro or base load unit was committed.

In fact, planning methods are based on prospective cost and choices are influenced by both the cost of owning and the cost of operating. The life of a hydro plant is considerably longer than that of a gas turbine so the economic cost per dollar invested is lower. Operating and maintenance costs are also lower. Therefore, even if only incremental capacity had to be served, planning would result in the selection of a hydro unit at a considerable capital cost premium over a gas turbine.

Further, planning considers the present worth of life fuel costs associated with any option.

If it is appropriate to classify fixed cost to energy where the fixed cost was incurred to avoid excessive fuel cost, then it is equally appropriate to classify fuel cost to demand where fuel cost is incurred to avoid excessive capacity charges. The differential fuel costs associated with gas turbine operation can thus properly be classified to demand.

Where capital costs only are considered (as in the case of peaker proxy and peaker credit methods), the life fuel costs should be capitalized and included in the calculation of the unit proxy cost. This is not done, probably because of the difficulty of determining an appropriate figure. If it were done, the unit proxy cost would be dramatically higher.

For these reasons, peaker proxy and peaker credit methods understate the demand component of fixed costs. Methods which use load-following plant as the proxy attempt to recognize the effect of energy cost on planning decisions, but tend to overstate it.

7. Peaker Analysis Applied to Long-Run Costs

The relative responsibility of demand and energy for system long-run cost is here examined using a peaker method.

Load growth is assumed to occur as indicated in NP-12. The growth is assumed to occur (a) due to increase of system demand with little or no increase in energy requirement, and (b) due to demand at high load factor. In the first case the added demand can be met by gas turbines, and in the second case base load thermal generation is required.

If other options are in fact available, their costs could be proxied as above.

Planning data is taken from GCB-4. However, the 50 MW gas turbine size cited therein is small compared to load growth. While specific planning considerations may well justify this size for a 1993 addition, a larger unit with lower unit cost would be economic under the scenarios considered here. Units of 100 MW would be reasonable, but for analytical convenience 95 MW unit capacity is assumed. (This is 2/3 of the 142.5 MW planned capacity for a fourth unit at Holyrood.)

The unit cost of a 95 MW unit is estimated from data used for regional planning by utilities in the Maritimes. Assuming that cost is a linear function of size, cost = \$A + \$B/KW.

The Maritime data gives:

$$39{,}330{,}000 = A + 45{,}000\ B$$

and

$$61{,}500{,}000 = A + 100{,}000\ B$$

from which $B/A = 19.0128 \times 10^{-6}$. This ratio is independent of dollar basis or inflationary effects and is applied to the \$932.9/KW cost of a 45 MW unit cited in GCB-4. From this, the unit cost of a 95 MW unit is calculated as \$706.4/KW. For the base load thermal option, a fourth unit at Holyrood at \$1,198.5/KW is assumed. Escalation is immaterial for purposes of comparison and IDC, which would increase the difference between gas turbine (GT) and base load thermal (BT) options, is ignored.

Assuming that fixed O & M costs constitute half the total GT O & M costs, a real interest rate of 5.5%, 25-year GT life and 30-year BT life, the annual unit costs per KW are respectively:

Gas turbine:

Annual fixed charge	- 706.4(.074549)	= \$52.66
O & M	- .5 x 7.28	= 3.64
Total		= \$56.30

Base load thermal:

Annual fixed charge	- 1,198.5(.068805)	= \$82.46
Fixed O & M		= 15.27
Total		\$97.73

The expansion program under each option is shown in Table 3. Because the capacity installed under each option is equal after 3 gas turbines and 2 base load units have been installed, end-effect errors are negligible if only a 6-year period is considered.

TABLE 3

GENERATION EXPANSION PROGRAMS

YEAR	SYSTEM PEAK MW	CAPACITY REQUIRED MW	GT OPTION INSTALLED	GT OPTION CAPACITY MW	BT OPTION INSTALLED	BT OPTION CAPACITY MW
1993	1591	1892	GT(95)	1932	BT(142.5)	1979.5
1994	1627	1935	GT(95)	2027		1979.5
1995	1666	1981		2027	BT(142.5)	2122
1996	1688	2007		2027		2122
1997	1750	2081	GT(95)	2122		2122
1998	1785	2122		2122		2122
1999	1828	2217	GT(95)		BT(142.5)	

Note: Capacity requirement is based on an 18.9% reserve. The actual requirement would differ with type, size and number of units installed. An actual calculation is beyond the scope of data and resources available.

The present worths of each option are calculated in Table 4.

TABLE 4

PRESENT WORTHS OF ANNUAL COSTS

YEAR	INDEX	GT OPTION ANNUAL COST $ x 1000	GT OPTION PRESENT WORTH $ x 1000	BT OPTION ANNUAL COST $ x 1000	BT OPTION PRESENT WORTH $ x 1000
1993	0	5,349	5,349	13,927	13,927
1994	1	10,697	10,139	13,927	13,201
1995	2	10,697	9,611	27,853	25,025
1996	3	10,697	9,110	27,853	23,720
1997	4	16,046	12,952	27,853	22,483
1998	5	16,046	12,277	27,853	21,311
			59,438		119,667

If the demand/energy ratio is calculated on simple unit cost, the result is 56.3/97.73 = 58% capacity, 42% energy. If the extra present worth costs due to larger unit size of the BT option are included, the result is 59,438/119,667 = 50% capacity, 50% energy.

The foregoing results depend on a number of assumptions which if varied, would affect the outcome. They should therefore be considered as indicative rather than precise.

8. The Plant Factor Method

The Plant Factor method is in some respects similar to peaker methods. Like the Composite Peaker, it requires separation of the utility's capacity into load-following and base-load categories. However, it uses plant (or capacity) factor rather than plant cost as the criterion for classification. This difference at once circumvents the difficulties encountered in applying peaker methods. However, some adaptations are necessary.

It is usual to assign specific plants to each category and then calculate the combined plant factor for load-following plant. This plant factor is then used as the criterion for classification, just as the peaker unit cost is used under the peaker methods.

To adapt the method to the NLH system, the base load is taken as the least load on the typical summer day load curve (GCB-3, page 5 of 6). The system base load capacity is assumed to be a portion of the hydro capacity. Availability of hydro plant is assumed to approximate 95%, so the amount of base load capacity is determined as (base load/.95). The remainder of system capacity is then assigned to the load-following category. The load-following energy is calculated as system total less base load energy. The load-following capacity factor is then obtained and used to classify costs of each system plant.

This procedure is applied to the NLH system in Exhibit GCB-3.

The method appears to give fairly reasonable results. Experience elsewhere suggests that the plant factor method tends to classify more costs to capacity than most other analytical approaches.

Filed Sept. 21/92
Dr. G. C. Baker
Supplemental
Evidence

PROVINCE OF NEWFOUNDLAND AND LABRADOR

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF the Electric Power Control Act

- and -

IN THE MATTER OF a Generic Hearing, on *inter alia*, the Cost of Service Methodology used by Newfoundland and Labrador Hydro-Electric Corporation.

S U P P L E M E N T A R Y   D I R E C T   E V I D E N C E

O F

G. C. B A K E R

Q Why are you submitting supplementary evidence?

A Since filing of my direct evidence, more information has become available, including the evidence of Mr. Brockman and Dr. Olsen. From these sources and from the proceedings, some matters have arisen on which additional comment seems appropriate. These relate to:

- Further examination of the Peak Credit method.
- Classification of generation.
- Functionalization of transmission lines.
- Classification of transmission lines.
- Sharing of the rural revenue deficiency.

Q What are your comments on the Peak Credit method?

A In his supplementary testimony, Mr. Brockman agreed in principle that it would be appropriate to include capitalized gas turbine fuel costs in the peaker cost. My original testimony pointed out that plant life was an addition cost factor implicitly included in system planning.

The effect these planning considerations could have on the perceived peaker cost, and in consequence on the classifications resulting from application of the peak credit method, is illustrated in a two-page addendum to Appendix 2 of my testimony.

Mr. Brockman pointed out that the life capacity factor of a gas turbine is an unknown quantity. I agree with this and have used representative values for purposes of illustration. The approach is defined at page 8 using a 2% life-levelized capacity factor and a fuel price real escalation rate of 1%. The results are shown in Table 5, Page 9. Results for other capacity and fuel price assumptions are shown in Table 6.

In my opinion, the most reasonable assumptions are 0.5% capacity factor and escalation of 1 or 2%. These assumptions yield demand classifications in the 40 to 45% range. However, the Tables are intended only to show the leverage exerted on the results of this method if planning considerations are included. It omits O & M and uses gross rather than differential fuel cost, and therefore has only minor probative value.

Q How important is the classification of fixed generation cost?

A It exerts more leverage on allocations to rate classes than any other aspect of cost of service methodology.

Q How do you view the positions of the parties on this aspect?

A Generally speaking, the testimony indicates that Dr. Sarikas, Mr. Brockman and I all consider that a fairly large share of fixed cost should be attributed to energy use. As I interpret his testimony, Dr. Sarikas relies on the Average and Excess Allocation to reduce the proposed classification of 69% demand. If the A & E method did in fact allocate 55% of the demand cost as an energy cost, the final result would be a classification of about 31% to demand. Mr. Brockman arrives at a figure of 33% by using the Equivalent Peaker method, which is in my testimony referred to as the Peak-Credit or Peaker Credit method.

Dr. Olsen uses a figure of 97% demand, also with the expectation that this would be effectively reduced by Average and Excess allocation; presumably to about 44% demand.

It is evident that the actual effect of an Average and Excess allocation will be of great importance to the Board in determining the proper split of generation cost.

Q Does Exhibit RAS 3 change your opinion on the energy weighting effect of Average and Excess?

A No, not at all. Simple models of utility systems are often used to demonstrate generally applicable principles. However, in order to provide a valid conclusion, such models must, in all details affecting the conclusion, be more or less typical of real life. Model conditions cannot violate physical constraints.

The model presented in RAB-3 does not comply with these conditions of validity. It assumes that both CP demand and NCP demand will remain fixed while load factor changes from 0 to 100%. For a single customer this is unlikely, but possible. For a class it has a vanishingly small probability of attainment.

A If the model were changed to keep either CP or NCP at a fixed value and to allow the other demand to vary, for instance, in conformity with a Bary curve, the line of cost versus load factor could be made to go up with increasing load factor, as in the graph presented, to trend down or to follow a sinuous course; depending on the load factors and excess demands attributed to the various classes.

The model is invalid for another reason. It is out of context with the problem at hand. The problem at hand is whether a cost of service study using the Average and Excess method does, or does not, allocate a part of generation fixed costs to rate classes in proportion to their energy use. That is what is meant by energy weighting, or energy recognition, in my testimony.

The input data for a cost of service study is essentially a snapshot view of the system. Class demands, energy use and load factors are actual for a retrospective study or estimated in the case of a prospective study. They are single valued.

Load factor changes from year to year are typically small, and if any changes do occur, they will be reflected in future cost of service studies. However, the problem of concern in this hearing is not how a cost of service study in 2002 will compare with a cost of service study in 1992. The problem is how the 1992 study will allocate costs between classes.

Thus, the relevant portion of the graph in RAB-3 is not the whole graph, but a single vertical line drawn to correspond with the class load factors as they exist at the time of the study.

That is why the graph is out of context with the problem at hand.

There is, in any event, no need to rely on contrived models to determine the facts. They can be explored in terms of Hydro's actual system.

To do this, I have provided a reconciliation of CP and Average and Excess allocations, as shown in IC-2. The results are shown in Exhibit GCB-6.

Q Please describe the Exhibit and explain what it demonstrates.

A The first line of the exhibit shows the costs allocated to NP, the Industrial class and the rural classes as a whole under Hydro's proposed allocation. The figures are taken from IC-2, line 1.

Lines 2, 3, and 4 calculate and add back the diversity benefits on Coincident Excess kilowatts which have been provided by the Excess demand allocation.

Lines 5, 6, and 7 remove the charges on Non-coincident Excess kilowatts which have likewise been levied by the Excess demand allocation.

Now, since we know that the CP method provides no energy weighting whatever, the only further step necessary to reconcile the Average and Excess and the CP allocations is to remove the energy weighting provided by the former. This is done at line 8, and the final result coincides with the CP allocation, as taken from IC-2, line 4.

Of course, line 8 was unnecessary, but has been included in the Exhibit to emphasize the fact that the Average and Excess method provides zero recognition.

Q Mr. Brockman's supplementary evidence suggests that a further study will not help to clarify the appropriate demand/energy split of transmission cost. Is that correct?

A This may be the case. I found the available evidence insufficient to enable me to recommend a definite split and recommended further study in the hope of improving the situation. I am still of the opinion that an appraisal by Hydro staff, based on causal principles, would be of benefit.

However, the Board may wish to settle the issues immediately instead of letting them drag on. If this is the case, the Board may wish to have on record whatever indication I can give. Based on the present evidence, my preference can only be expressed as a range and I consider that a range of 75% to 90% demand would probably include the appropriate figure.

The answer would to some extent depend on whether lines serving the former PDD's are, or are not, specifically allocated. They obviously have a significant energy component due to diesel displacement and if they are specifically assigned would decrease the energy component of common cost.

Q Dr. Olsen suggests that the rural revenue deficiency should be allocated on the basis of plant-related costs of the subsidizing classes. Would this be suitable?

A Dr. Olsen's suggestion is predicated on the assumption that "if tariffs are set in a rational manner, the rural rate should at least collect all variable costs".

It is not by any means clear to me that such an assumption holds true. This is not to suggest in any way that Hydro's rate making is irrational, but the history of rural rates leaves domestic rates with a lifeline block and effectively imposes a ceiling on all rates.

If one regards NP rates as a ceiling and further assumes that NP rates are cost-based, then the following data may throw some light on the subject:

- For demand costs, allocated unit costs of the subsidized classes are about 2.45 times those of NP.

- For energy costs, the unit costs of subsidized classes are about 2.46 times NP unit costs.

These data do not appear to support Dr. Olsen's assumption, and although not conclusive, suggest that allocation of the deficit on demand cost may be inappropriate.

Q As a final question, how did you arrive at your recommendation of a demand/energy split in the range of 45 to 50% demand related?

A The peaker credit method omits some planning considerations that are material and are difficult to quantify. In consequence, it does in my opinion overstate energy responsibility. On the other hand, the plant factor method, which uses all load-following plant as the proxy, understates energy responsibility. Because of the difficulty of correcting these faults, I simply offset them by averaging to arrive at a figure of about 45% for the demand component.

This result, together with the load factor classification, provided a benchmark in the 45% region for what I tend to regard as operational indicators.

A Another set of figures, relating to utilization of capability, system expansion responsibility and long-run cost, was grouped in the 50 to 55% range.

I regard the operational indicators as somewhat more dependable than the others, but wished to give some recognition to the present trend of decreasing load factor.

In my opinion, a figure in the 45% to 50% demand range would provide the best balance between these various and conflicting considerations, and my recommendation was made accordingly.

Filed
Sept 21/92.
Dr. Baker (B.C)
Supplemental

Appendix 2
Addendum

9. Inclusion of planning considerations in peaker credit method.

9.1 Expected plant life.

Plant Type	Life (yrs)	FCR(a)	FCR Ratio (b)
Gas Turbine	25	.074549	1
Base load thermal	30	.068805	1.083481
Hydro	70	.056328	1.323497

(a) FCR is the fixed charge ratio, the levelized annual payment required to amortize an investment of 1 over plant life . It is here calculated at 5.5% real interest.

(b) This is the ratio of Gas Turbine FCR to that of each plant type. From a planning perspective an investment of $1 for gas turbines (GT), $1.083481 for base load thermal (BT) or $1.323497 for hydro will have equal cost over an indefinitely long planning period.

GT Actual unit Cost = $335.8

GT Cost for classifying BT = 335.8 x 1.083481 = $363.81

GT Cost for classifying Hydro = 335.8 x 1.323497 - $444.40

9.2 Capitalized Fuel Cost
A life levelized capacity factor of 2% and an oil price of 21 cents/litre escalating at 1% per year are here assumed.

GT Fuel Cost/KWH = $.21 x 12,877KJ/KWH ÷ 38,464KJ/L = $.0703
Present worth factor = (1 - (1.01/1.055) E25) / (1-1.01/1.055)
= 15.56

Capitalized fuel cost = $.0703 (.02) (8760) (15.56) = $191.64

9.3 Total Unit Cost

For BT classification - $363.81 + $191.64 = $555.45
For Hydro classification - $444.40 + $191.64 = $636.04

Appendix 2
Addendum

9.4

Table 5
Classification by Peaker Credit Method

Plant	(1) Unit Cost $/KW	(2) GT Cost $/KW	(3) Demand %	(4) Energy %
Peaking			100	0
Holyrood Hydro	671.0	555	82.8	17.2
Bay D'Espoir	1018.8	636	62.4	37.6
Snooks Arm	338.3	636	100	0
Venams Bight	507.5	636	100	0
Hinds Lake	1741	636	36.5	63.5
Upper Salmon	2453	636	25.9	74.1
Cat Arm	2518	636	25.3	74.7
Paradise River	2744	636	23.2	76.8
Total Hydro			43.8	56.2
Total System			55.8	44.2

9.5

Table 6
Peaker Credit Classification
Sensitivity to Assumptions

Capacity Factor (life levelized) %	Real Fuel Escalation % / year	Classification To Demand %
0.5	1	43.0
	2	43.4
1.0	1	47.3
	2	48.1
2.0	1	55.8
	2	57.5

Reconciliation of A & E and CP Allocations

	Allocations In $9000's) N L P	Industrial	Rural
A & E Allocation: .56% Demand, 44% Energy			
per IC exhibit 2, line 1	175,286	37,165	27,994
Add back diversity benefits on coincident excess KW:			
NP (1,004,786 - 502,042) $6.87844	3,458		
IND (153,664 - 145,672) $6,87844		55	
RUR (71,254 - 35,446) $6.87844			246
Remove charges on NC Excess KW:			
NP (1,017,522 - 1,004,786) $80.688977	(1,028)		
IND (168,722 - 153,664) $80.688977		(1,215)	
RUR (90,051 - 71,254) $80.688977			(1,516)
Remove energy weighting due to average demand allocation on energy	0	0	0
CP Allocation			
56% Demand, 44% energy Per IC Exhibit 2, Line 4	177,716	36,005	26,724

Notes

1. $S/C = $107,682E3 / 1,229,704 = $86.56741 (from RAB schedules 3.2A & 4.1)
2. Diversity benefit = S/C (D-1) / (D-F) / KW
   NC Excess Cost = $S/C (1-F) / (D-F) / KW
   (From exhibit GCB-1)
3. The system diversity factor D and load factor F are calculated from RAB schedule 4.1 and the class demand data is taken from the same source.
4. The diversity benefit / KW is $6.87844 and the charge per excess KW is $80.688977.