Q. Please provide Mr. Brockman's evidence filed with the Board on behalf of Newfoundland Power at the hearing in which the Board initially approved the cost of service methodology for Newfoundland Power including the Rural Deficit allocation among its customer classes.

A. Attachment A provides a copy of Mr. Brockman's evidence filed with the Board on behalf of Newfoundland Power at the hearing in which the Board initially approved the cost of service methodology for Newfoundland Power including the Rural Deficit allocation among its customer classes.

Newfoundland Power 1996 General Rate Application

Larry Brockman Evidence

NEWFOUNDLAND LIGHT & POWER CO. LIMITED

DIRECT TESTIMONY OF LARRY BROCKMAN

Q. Please state your name and professional qualifications.

A. My name is Larry B. Brockman. I am a Vice President with the Utilities Division of Electronic Data Systems (EDS). EDS provides a wide range of information technology services to over 50 industries worldwide, including planning and financial software and consulting for electric and gas utilities. EDS owns and supports both the PROMOD IV and PROSCREEN II planning and financial models used by many utilities in the U.S. and Canada.

I have over 20 years of experience, in planning, regulation, teaching, and consulting for electric and gas utilities. I have appeared before this Board on 4 previous occasions. I have appeared as an expert witness on planning and ratemaking before regulatory bodies in Nova Scotia, Newfoundland, Florida, Oklahoma, Colorado, and the United States Federal Energy Regulatory Commission (FERC). A more complete resume of my experience is attached as Exhibit LBB-1.

Q. Mr. Brockman what is the purpose of your evidence in this proceeding?

A. I was asked by Newfoundland Power to review several of their proposed cost of service and rate design changes, with respect to generally accepted rate design principles and practices.

In particular I was asked to review:

(1) The cost of service study changes Newfoundland Power is proposing in this proceeding, and the appropriate use of the cost of service study in rate design.

(2) Newfoundland Power's proposal to implement basic customer charges for all rate classes.

(3) The assignment of the rural rate subsidy to the first 700 kWh of usage for the Domestic and Small General Rate 2.1 classes.

(4) Newfoundland Power's proposed changes to the Rates 2.2, 2.3, and 2.4 energy only rates and elimination of Minimum Billing Demands for Rates 2.2, 2.3 and 2.4.

Q. Please describe the changes Newfoundland Power has made to its cost of service methodology.

A. Newfoundland Power has proposed that the cost of service study to be used in this proceeding incorporate, where appropriate, the Board's findings and recommendations from the Generic Cost of Service hearing for Hydro held in 1992. This represents several changes in the way Newfoundland Power has allocated costs in the past.

The major changes are:

(1) Classification of Newfoundland Power's hydraulic plant from 100% demand to system load factor on energy;

(2) Allocation of Newfoundland Power's Generating Plant (Hydraulic and Thermal) from Non Coincident Peak (NCP) to 1 Coincidental Peak (CP).

(3) Allocation of Newfoundland Power's Transmission Plant from NCP to 1 CP.

(4) Allocation of Purchased Power Transmission Demand Costs from NCP to 1 CP; and

(5) Allocation of Purchased Power Generation Demand Costs from NCP to 1 CP.

These five changes are consistent with the Board's Report to the Minister of Mines and Energy concerning Newfoundland & Labrador Hydro's Cost of Service Methodology on February, 1993. Detailed results of the Cost of Service study may be found in Mr. Connors' evidence.

Q. Do you agree with the changes to Newfoundland Power's cost of service methodology as described?

A. Yes. While I argued, and still believe, that a 5 CP allocation would be more appropriate to allocate demand costs for Hydro's generation and transmission system, the Board clearly set out a study requirement for Hydro to present at its next rate hearing, before the final decision on 1 CP vs multiple CPs is made (p. 24 of the above noted report).

Newfoundland Power is content to let the issue rest until Hydro's next application, and has used a 1 CP allocation as a result. This means Hydro's generation and transmission demand costs are treated consistently by both utilities.

I should also point out that Newfoundland Power has not included the Rural Deficit in the calculation of revenue to cost ratios in their cost of service study. Since the deficit is not a cost associated with electricity service to Newfoundland Power's customers, this is appropriate.

Q. How should the results of Newfoundland Power's cost of service study be used in the rate design?

A. Cost of service studies are used as a guide to rate design in two ways. First, they are used to determine the revenue allocation to the rate classes. This is usually done by examining the revenue to cost ratios produced and allocating more revenues to classes that are being served at below cost, and less or none to those already being served at greater than cost.

Most regulatory bodies and rate designers accept a range of revenue to cost ratios. That is, they do not necessarily feel it is required to achieve a 100% revenue to cost ratio for all classes. I generally recommend a target range of 90% to 110% for revenue to cost ratios, but do not get especially concerned unless the ratios are outside 80% to 120%.

There are several reasons for not adopting a stringent revenue to cost ratio standard of 100% for every class. First, there are many differences of opinion as to how the cost of service study should be performed. Second, history has placed many classes too far from 100% revenue to cost, to get there in one fell swoop. In addition, some argue that all classes do not pose the same business risk to the utility and should therefore not be imputed the same rate of return. Finally, the billing determinants and costs are always changing, so almost no one ever gets to 100%, anyway.

The second way in which cost of service studies offer guidance is in the rate design process within classes. Specifically, the cost of service study can be used to provide what is known as "unit costs" costs of energy, demand and customer costs (for the unit cost results of Newfoundland Power's cost of service study, see TAC-1, p.3).

The unit costs from the cost of service study are compared to the existing and proposed rates for customer charges, energy charges, and demand charges to help decide whether they should be raised or lowered. There are of course many other considerations such as rate impacts, comparisons to marginal costs, revenue stability, understandability and acceptance which will affect the final rate design, but unit costs are an important tool for the rate designer.

Q. What changes are Newfoundland Power proposing with respect to basic customer charges?

A. Newfoundland Power is proposing to bring basic customer charges in the Domestic Rate, 1.1, and General Service Rate 2.1, closer to cost. They also propose implementation of basic customer charges in Rates 2.2, 2.3 and 2.4, where there are presently none. The following table summarizes the proposed changes:

Rate Class	Present Basic Customer Charge	Customer Unit Cost 1994 Cost of Service Study	Proposed Base Customer Charge
1.1	$16.32/mo	21.47	17.27/mo
2.1	$18.57	23.48	19.57/mo
2.2	-	43.15	24.00/mo
2.3	-	148.53	$100.00/mo
2.4	-	299.74	$200.00/mo

One of Newfoundland Power's rate design goals was to institute cost based basic customer charges for all general service classes, but impacts on smaller customers in each class limited how much could be accomplished in this rate case.

Q. Do you agree with Newfoundland Power's proposals on basic customer charges?

A. Yes. I agree with them for several reasons. First a basic tenet of fairness is that we base rates on costs. It is a well accepted fact that there are 3 basic components of electricity costs. They are: customer costs; energy costs; and demand costs. Because there are relatively large and small customers in many classes, if we simply spread customer costs over energy rates, or demand rates, larger customers pick up more than their fair share of these costs. Basic customer charges assign these costs more fairly.

Second, cost based customer charges give the utility a measure of revenue stability. That is, cost based customer charges ensure that even if a customer uses no power in a given month, the customer will at least pay for the costs of providing a meter, a service drop, any minimum distribution plant included, and basic billing costs. Newfoundland Power is proposing to do away with minimum billing demands in Rates 2.2, 2.3 and 2.4. This will tend to lessen revenue stability for these classes and the basic customer charge will help mitigate that loss.

For both these reasons, I support Newfoundland Power's proposal to institute basic customer charges in Rate 2.2, 2.3 and 2.4, and get the basic customer charges closer to cost in Rates 1.1 and 2.1.

Q. How were the recommended revenue to cost ratios for Newfoundland Power chosen?

A. As Mr. Connors describes in his evidence, the recommended ratios were chosen by balancing the Bonbright goals of good rate design. These goals include: meeting revenue requirements; achieving fairness; sending efficient price signals; maintaining stability; and, setting rates that can be practically administered.

The 1994 cost of service study is significantly different than the one used in 1992 for Newfoundland Power. This is due to Newfoundland Power's adoption of the Board's findings from Hydro's generic cost of service proceeding. There were some shifts in cost responsibility between classes due to the new classifications and allocations of generating and transmission assets inherent in the Board's decision. As Mr. Connors' evidence shows, these changes brought the revenue to cost ratios closer together.

The table below shows the revenue to cost ratios for existing rates in the new 1994 cost of service study.

Rate Class	Revenue to Cost Ratio
1.1 Domestic	94.5%
2.1 General Service	104.5%
2.2 General Service	115.1%
2.3 General Service	107.8%
2.4 General Service	103.9%
4.1 Streetlighting	104.8%

As the table shows, all classes, except Rate 2.2 are within plus or minus 10% of cost.

After weighing the goals of meeting the revenue requirement; fairness; efficiency; stability; and, administrative practicality, Newfoundland Power arrived at the following general guidelines for this case:

1. All classes should receive at least some increase.
2. The revenue to cost ratios of the general service rate classes 2.1, 2.2, 2.3 and 2.4 should be made more equal; and
3. Limit the increase to any class to no more than 1%, plus the overall average increase.
4. While not strictly a revenue to cost issue, it was also decided at this time to limit the increase to any customer on an annual basis, to ten percent, plus the overall percentage increase on that customer's rate class (unless special circumstances prevail or the dollar amount is small).

Q. Why was it decided all classes should receive some increase?

A It was not considered fair to have some classes not participate in the increase to some degree. The increase to Rate 2.2, however, was held to 1.2%, after considering that class is already at 115% of cost.

Q. Why were the increases held to no more than 1% greater than the overall increase for any class?

A. This was done to accommodate gradualism, and because the water heat and space heat load in the domestic sector is facing severe competitive pressures. In addition it was considered unfair to give any class more than 1% greater than the overall increase.

Q. Why is it important to bring the revenue to cost ratios of the General Service classes closer together?

A. It is important to bring the revenue to cost ratios of the general service classes closer together, because there is migration between these classes. The removal of the minimum demands in the General Service classes was necessary to cure the problems with smaller customers in the classes being treated unfairly, compared to the larger customers in these classes, and because the minimums created a lot of customer misunderstanding and dissatisfaction. These issues are discussed in more detail later in my evidence.

Unfortunately, removal of the minimum demands also created a situation where customers close to the minimum or maximum demand levels of the class can move from one class to the other with significant changes in rates, under the present structure. Since there is not much difference in unit cost to serve a customer who uses only a little more or a little less, there should not be a large difference in rates. Failure to recognize this can lead to a situation where customers attempt to increase their demands for very short periods, simply to gain admission to another class and a lower rate. Such an activity by customers is an inefficient use of the electrical system, and should be discouraged through the proper design of rates.

There will always of course, be some difference in unit costs between rate classes, but these should primarily reflect voltage level loss differences and differences in billing demand diversity. When General Service classes have different revenue to cost ratios, we introduce another element, which further contributes to differences in unit costs. For this reason, Newfoundland Power has proposed giving only a small increase to Rate 2.2 and larger increases to 2.1, 2.3, and 2.4. This will bring all general service classes more into parity with one another, and help to solve the transition problems.

Q. **Considering all these criteria what are the final recommended increases by class, and what are the resulting revenue to cost ratios?**

A. The table below shows the recommended increases by class, and resulting revenue to cost ratios.

Rate Class	Increase	Proforma Revenue to Cost Ratios (per Exhibit TAC - 1, Page 1)
1.1 Domestic	5.8	95.3%
2.1 General Service	5.4	105.1%
2.2 General Service	1.2	111.0%
2.3 General Service	5.4	108.4%
2.4 General Service	5.4	104.5%
4.1 Streetlighting	1.0	101.0%
Overall	4.9	

With the proposed increases all of the classes should be within the recommended range of 90% to 110% of cost, with the exception of Rate 2.2 which is at 111% of cost.

Q. Do you consider these recommended increases and the resulting revenue to cost ratios to be appropriate?

A. Yes. I think they appropriately balance the many goals of good ratemaking Newfoundland Power applied in setting them.

Q. Please discuss Newfoundland Power's proposal to assign the rural rate subsidy to the first 700 kWh of consumption in the Domestic class.

A. At the current time, all of Newfoundland Power's customers subsidize Hydro's rural customers. $14.7 million of the rural rate subsidy is currently allocated to Newfoundland Power's domestic customers, and spread across all their electric consumption. As discussed extensively at the Rural Rate Inquiry, including these subsidies in Newfoundland Power's rates is unfair and distorts efficient price signals to Newfoundland Power's customers. Newfoundland Power is now proposing to collect the Domestic class' share of the subsidy from only the first 700 kWhs of energy consumption.

The Board captured these ideas succinctly (at page 175 of the October 10, 1995 Report to the Minister of Natural Resources), when they stated,

> "The present surcharge on electricity alone is not equitable, but can be redesigned in the form of a tax which is both more equitable and more efficient. Such a tax can be designed by broadening the base to include not only electricity but also heating fuel."

Given that Government has not yet, (and may never), remove the surcharge from Newfoundland Power's customers, the challenge is to design rates which accomplish the Board's goal as well as possible.

Q. Does the Newfoundland Power proposal to assign the rural rate subsidy to the first 700 kWh in the domestic class accomplish these goals?

A. Yes. Newfoundland Power's proposal accomplishes these goals for three basic reasons: (1) the subsidy is in effect a tax, and should not be collected based solely upon electricity consumption, but from other forms of energy uses as well; (2) the Board should try to reduce the subsidy as much as practical, and; (3) given that Newfoundland Power's domestic customers must pay the rural rate subsidy (until and unless government accepts the Board's recommendations from the Rural Rate Inquiry), it is important to distort efficient price signals as little as possible when collecting the subsidy.

Q. Explain how Newfoundland Power's proposal to collect the subsidy from the first 700 kWh of energy consumption in the Domestic Rate satisfies the Board's goal of placing the subsidy more equally on other forms of energy than the present situation.

A. At the present time, the subsidy is collected uniformly across all kWh consumption in the Domestic class. Because the subsidy is collected as a 0.56 cent/kWh adder to all Domestic consumption, customers who heat with wood or oil (and consequently use less electrical energy) pay less of the subsidy then those who use electric heat. The following table shows the amount of subsidy paid at various kWh consumptions:

Monthly kWh Consumption	Subsidy Paid/Month
250	$1.40
500	2.80
700	3.92
1000	5.60
1500	8.40
2000	11.20

Presumably the customers using less than 700 kWh/mo are not using electric heat and are using oil or wood to heat their homes. Due solely to the choice of heating fuel, they are escaping the payment of an equitable share of the subsidy. As the Board pointed out, this is neither fair, nor efficient.

Under Newfoundland Power's proposal, the subsidy would be spread only over the first 700 kWh of consumption in the Domestic class. Under that proposal, the adder would be 1.182 cents per kWh. This gives the following subsidies paid by various consumptions.

kWh Consumption	Subsidy Paid/Mo.
250	$2.96
500	5.91
700	8.27
1000	8.27
1500	8.27
2000	8.27

Newfoundland Power's proposal better accomplishes the Boards goals of collecting the subsidy more equitably from electric customers regardless of their choice of heating fuel.

Q. Did you consider simply assigning the rural rate subsidy to the fixed charge?

A. Yes. Assigning all of the subsidy directly as a fixed charge actually accomplishes the basic efficiency goals better than assigning the rural rate subsidy to the first 700 kWh block in the domestic class, but it also has some undesirable effects. It gives a higher increase to the smaller users than Newfoundland Power's proposal.

Newfoundland Power tested the impacts of putting all the subsidy in the basic customer charge. The charge would be approximately $7.00 per month per Domestic customer. With the other increases in this case, it was felt that the impact was too great. Newfoundland Power already has a relatively high basic customer charge and impacts to small customers would be more severe. For that reason, Newfoundland Power decided that this method was less desirable.

Q. How does collecting the subsidy from the first 700 kWh in the Domestic class reduce the deficit?

A. The rural subsidy is created in large part by the requirement to price Hydro's rates in Rural Newfoundland at Newfoundland Power's rates. Unless and until government accepts the Board's recommendation to remove the subsidy from Newfoundland Power's electric rates, the total amount of the subsidy can be reduced by raising the first 700 kWh block. Assigning the subsidy to the first 700 kWh applies this charge to both Newfoundland Power's and Hydro's customers and it will reduce the deficit because all Hydro's Rural domestic rates are set equal to Newfoundland Power's rates for the first 700 kWh.

Q. Why does Newfoundland Power's proposal to collect the rural subsidy in the first 700 kWh of the domestic rate distort efficient pricing less than collecting it over all consumption?

A. To achieve efficient pricing it is important to price as close as possible to marginal costs. There is much debate about whether efficient pricing also demands including some of the long run marginal costs in electricity prices, and whether the fact that other goods and services may not be priced at marginal cost, invalidates the benefit. Those favouring short run marginal costs usually want to let the customers take advantage of short run overcapacity situations, and make their own decisions about long run price trends. Those favouring long run marginal costs believe that customers should receive prices today which reflect estimates of long range price trends. The debate on whether other goods and services are priced at marginal costs usually centers around whether marginal cost pricing gives all the efficiency of competitive markets or only "second best solutions."

In the end, most economists tend to agree with Charles Phillips, in *The Regulation of Public Utilities*, Public Utilities Reports 1988, when he says,

> "Despite the qualifications, economic efficiency requires marginal cost pricing."

It is not usually practical to set all rates at marginal costs, so many rate designers try to set at least the run-out rates (or tailblocks) as close to marginal costs as seems fair and practical.

The current Domestic runout energy rate is 6.373 ¢/kWh, including the rural rate subsidy amount of approximately 0.56 ¢/kWh. The marginal costs at the distribution secondaries, where Domestic is served, have been estimated by Newfoundland Power as shown on Exhibit LBB-2 for 1996 to 2000. The short run marginal costs on this exhibit range between 4.1 and 4.2 ¢/kWh. If we include longer run capital expansion estimates Exhibit LBB-2 shows the marginal costs reaching 5.8 cents in 1996 to 6.0 cents in 2000. The runout rate is thus significantly above short run marginal costs and the addition of the 0.56 ¢/kWh of rural rate subsidy makes it even higher.

Q. Do you agree with the way Newfoundland Power is recommending assignment of the rural rate subsidy to rates in the general service rate classes?

A. Yes. In the General Service class Rate 2.1, the assignment of the subsidy to the first block of 700 kWh is virtually the same as for the domestic class. The same justifications as I gave for the domestic class apply. It is more fair to recover the subsidy in the early blocks, and putting the recovery in the first block will reduce the subsidy. In addition, it appears more efficient to put the subsidy in the early consumption blocks.

For Rates 2.2, 2.3 and 2.4, Newfoundland Power is already recovering the subsidy in the first energy blocks and no change is proposed. All the same reasons as were given for doing this in the domestic class apply here as well.

Q. Please describe the changes Newfoundland Power is proposing in General Service Rates 2.2, 2.3 and 2.4.

A. Newfoundland Power is proposing the elimination of minimum billing demands for all these classes, and a reduction in the maximum energy-only rates in these classes, as well. There are several reasons for these changes. Some Newfoundland Power's customers who move from Rate 2.1 to Rate 2.2, from Rate 2.2 to Rate 2.3 or from Rate 2.3 to Rate 2.4, currently encounter very large bill increases when doing so. Since customers who are on the border line between rate classes require only small increases in consumption to move from one rate to another, there are not dramatic differences in the cost of serving them. If the rates track costs well, there should not be dramatic changes in the electricity bills to these transitioning customers.

Q. Do you support Newfoundland Power's proposal to eliminate the minimum billing demands in these classes?

A. Yes. Rates 2.2, 2.3 and 2.4 all currently contain minimum billing demand provisions, which are creating the transition problems mentioned above. In Rate 2.2 there is a minimum billing demand of 10 kW. In Rate 2.3 the minimum billing demand is 110 kVA. In Rate 2.2 the 10 kW represents the minimum demand amount necessary to move the customer into the class from Rate 2.1. In Rate 2.3 the 110 kVA represents the transition demand level which moves customers into the class from Rate 2.2. Similarly, the 1000 kVA minimum billing demand for Rate 2.4 represents the demand level moving customers up from Rate 2.3.

Smaller customers in all these classes often have demands in some months that are less than the minimum demands that moved them into the class. Forcing them to pay year round demand charges at the minimum demand for entering the class amounts to a 100% ratchet for them, whereas such a ratchet does not affect the larger customers in the class.

Larger customers in these classes pay a minimum monthly charge of $2.25 per kVA, on their maximum demand for the previous 12 months. Compared to the normal demand charges of between $6.24/kVA and $7.96/kW in the winter this is effectively only a demand ratchet of 28% to 38%.

Smaller customers in Rates 2.2, 2.3 and 2.4 do not understand why they are billed on the minimum billing demand for their class, when their demands are often much lower in some months. It is also not fair to subject them to what amounts to a 100% ratchet when other customers receive only 28% to 38% ratchets. To eliminate both problems and treat both large and small customers in the class fairly, I support Newfoundland Power's proposal to eliminate the minimum billing demand for Rates 2.2, 2.3 and 2.4.

Q. **Please describe the changes Newfoundland Power is proposing in the energy-only charge for Rates 2.2, 2.3 and 2.4.**

A. Newfoundland Power is proposing to change the present energy-only charge in Rates 2.2, 2.3 and 2.4 from 20.0 cents/kWh to 14 cents per kilowatt hour. They are doing this because there are many low load factor customers in Rates 2.2 and 2.3 who are paying more than the cost to serve them, and because there are small customers in Rate 2.2 who do not understand demand charges, or are too small to do anything about them. There are no current customers affected by this change in Rate 2.4.

Q. Do you agree with Newfoundland Power's proposals on the energy only rates in Rates 2.2, 2.3 and 2.4?

A. Yes. The energy-only provisions of Rates 2.2, 2.3 and 2.4 serve to protect customers with very low load factors from being overcharged. The problem is that the 20.0 cents/kWh for the present energy-only rate limit appears too high.

The Table below shows the equivalent energy charge that customers paying the demand and energy charges under the current Rate 2.2 at various low load factors would pay without an energy only rate, and the minimum monthly charge.

Equivalent Energy Charges to Customers Under Rate 2.2 with Demand Charges

Load Factor	Equivalent Rate (Cents/kWh)
1%	109.3
2%	58.1
3%	41.1
4%	32.6
5%	27.4
6%	24.0
7%	21.6
8%	19.8
9%	18.3
10%	17.2
15%	13.8
17%	13.0

The existence of the 20.0 cent/kWh maximum charge in this class limits the equivalent cents/kWh for customers in the class to that which would be paid by customers with approximately an 8% load factor. Newfoundland Power is now proposing to lower the limiting charge to 14 cents/kWh.

While, in general, adding demand charges to a customer's bill tracks costs better, there are exceptions, and the current 20.0 cents/kWh limit recognizes one of them. We know from investigations done by Constantine W. Bary, (*Operational Economics of Electric Utilities*, Columbia University Press, 1963, pp. 52-56), that above 30% load factor, there is a good chance that most customers in a class have close to the same coincidence factor. Below 25%-30% load factor, however, this relationship begins to change dramatically. Exhibit LBB-3 contains a copy of Bary's original curve. This curve is widely known as "The Bary Curve." The curve shows that customers with 8% load factors have only one half the coincidence factor as customers with load factors of 20% and above.

Since demand cost responsibilities are assigned to classes using the class average coincident factors, the unit demand costs derived from such allocations are appropriate for customers with load factors above 20%. Below those load factors, however, the average demand rates for the class will most likely assign too much demand responsibility to low load factor customers. To prevent this problem, some utilities cap the maximum energy rate that low load factor customers are required to pay. This is apparently what the current 20.0 cent/kWh energy-only charge in Rates 2.2, 2.3, and 2.4 was designed to do. For Newfoundland Power, however, the Bary curve indicates that the 20.0 cents/kWh probably overcharges very low load factor customers, as shown below.

Approximately 90% of the demand related costs of Newfoundland Power are associated with demands at the primary distribution levels and above. Since these costs all vary by either class non-coincident peak at primary level or class coincident peak at the transmission level, the Bary curve relationships for class coincidence versus customer load factor should hold for these costs. I have applied the relationships from the Bary Curve and the cost of service study, and get the following table showing appropriate energy-only costs for low load factor customers in Rate 2.2. Applying the low load factor relationships from the Bary curve, we see the results in the table below.

Newfoundland Power's Cost of Serving Customer's Rate 2.2 by Load Factor

Load Factor (%)	Bary Curve Coincidence (%)	Demand Costs ($/kWmo.)	Demand Plus Energy Costs (cts/kWh)
5	23	3.80	13.31
10	47	6.66	11.91
15	62	8.44	10.39
20	72	9.63	9.20
30	82	10.82	7.42

Supporting analysis for this table is shown in Exhibit LBB-4.

The final demand plus energy costs in this table also include the 1.97 cents/kWh of unit energy costs in the Rate 2.2 class. If full demand and energy costs were assigned to the energy charge for low load factors, the rate for 2.2 would be around 14 cents/kWh at load factors of 5% and less for load factors above that. Newfoundland Power's proposal to allow these rates to be capped at 14 cents/kWh for energy only therefore appears reasonable.

NEWFOUNDLAND LIGHT AND POWER CO. LIMITED

DIRECT TESTIMONY OF LARRY BROCKMAN

FEBRUARY 1996

REVISED - APRIL 1996

REVISIONS

Page 6	See new page 6	
Page 7	Line 16	Change "1994" to "1995"
Page 8	See new page 8	
Page 9	See new page 9	
Page 10	Line 13	Change "only a small increase" to "a small decrease"
	Line 14	Delete "larger"
Page 11	See new page 11	
Page 13	See new page 13	
Page 14	See new page 14	
Page 16	Line 16	Change "0.56 ¢/kWh" to "0.57 ¢/kWh"
Page 17	Line 1	Change "4.1 and 4.2 ¢/kWh" to "4.3 and 5.0 ¢/kwh"
	Line 2	Change "5.8 cents" to "6.1 cents" and "6.0 cents" to " 6.9 cents"
	Line 3	Change "0.56" to "0.57"
Page 21	Line 21	Change "90%" to "91%"
Page 22	See new page 22	
Page 23	See new page 23	
Page 24	See new page 24	

Revised

Rate Class	Present Basic Customer Charge	Customer Unit Cost 1995 Cost of Service Study	Proposed Base Customer Charge
1.1	$16.32/mo	20.70	16.94/mo
2.1	$18.57	22.77	19.12/mo
2.2	-	41.40	22.00/mo
2.3	-	141.31	$100.00/mo
2.4	-	275.55	$200.00/mo

One of Newfoundland Power's rate design goals was to institute cost based basic customer charges for all general service classes, but impacts on smaller customers in each class limited how much could be accomplished in this rate case.

Q. Do you agree with Newfoundland Power's proposals on basic customer charges?

A. Yes. I agree with them for several reasons. First a basic tenet of fairness is that we base rates on costs. It is a well accepted fact that there are 3 basic components of electricity costs. They are: customer costs; energy costs; and demand costs. Because there are relatively large and small customers in many classes, if we simply spread customer costs over energy rates, or demand rates, larger customers pick up more than their fair share of these costs. Basic customer charges assign these costs more fairly.

Second, cost based customer charges give the utility a measure of revenue stability. That is, cost based customer charges ensure that even if a customer uses no power in a given month, the customer will at least pay for the costs of providing a meter, a service drop, any minimum distribution plant included, and basic billing costs. Newfoundland Power is

Revised

The table below shows the revenue to cost ratios for existing rates in the new 1995 cost of service study.

Rate Class	Revenue to Cost Ratio
1.1 Domestic	94.8%
2.1 General Service	105.3%
2.2 General Service	115.2%
2.3 General Service	107.4%
2.4 General Service	102.2%

As the table shows, all classes, except Rate 2.2 are within plus or minus 10% of cost.

After weighing the goals of meeting the revenue requirement; fairness; efficiency; stability; and, administrative practicality, Newfoundland Power arrived at the following general guidelines for this case:

1. The revenue to cost ratios of the general service rate classes 2.1, 2.2, 2.3 and 2.4 should be made more equal;
2. Limit the increase to any class to no more than 1%, plus the overall average increase; and
3. While not strictly a revenue to cost issue, it was also decided at this time to limit the increase to any customer on an annual basis, to ten percent, plus the overall percentage increase on that customer's rate class (unless special circumstances prevail or the dollar amount is small).

Revised

Q. Why were the increases held to no more than 1% greater than the overall increase for any class?

A. This was done to accommodate gradualism, and because the water heat and space heat load in the domestic sector is facing severe competitive pressures. In addition it was considered unfair to give any class more than 1% greater than the overall increase.

Q. Why is it important to bring the revenue to cost ratios of the General Service classes closer together?

A. It is important to bring the revenue to cost ratios of the general service classes closer together, because there is migration between these classes. The removal of the minimum demands in the General Service classes was necessary to cure the problems with smaller customers in the classes being treated unfairly, compared to the larger customers in these classes, and because the minimums created a lot of customer misunderstanding and dissatisfaction. These issues are discussed in more detail later in my evidence.

Unfortunately, removal of the minimum demands also created a situation where customers close to the minimum or maximum demand levels of the class can move from one class to

Revised

Rate Class	Increase	Proforma Revenue to Cost Ratios (per Exhibit TAC - 1, Page 1)
1.1 Domestic	3.8	95.6%
2.1 General Service	3.0	105.3%
2.2 General Service	(1.0)	110.9%
2.3 General Service	2.9	107.4%
2.4 General Service	3.3	100.5%
4.1 Streetlighting	2.3	106.3%
Overall	2.9	

With the proposed increases all of the classes should be within the recommended range of 90% to 110% of cost, with the exception of Rate 2.2 which is at 111% of cost.

Q. Do you consider these recommended increases and the resulting revenue to cost ratios to be appropriate?

A. Yes. I think they appropriately balance the many goals of good ratemaking Newfoundland Power applied in setting them.

Q. Please discuss Newfoundland Power's proposal to assign the rural rate subsidy to the first 700 kWh of consumption in the Domestic class.

A. At the current time, all of Newfoundland Power's customers subsidize Hydro's rural customers. $14.9 million of the rural rate subsidy is currently allocated to Newfoundland Power's domestic customers, and spread across all their electric consumption. As discussed extensively at the Rural Rate Inquiry, including these subsidies in Newfoundland Power's rates is unfair and distorts efficient price signals to Newfoundland Power's customers. Newfoundland Power is now proposing to collect the Domestic class' share of the subsidy from only the first 700 kWhs of energy consumption.

Revised

Q. Explain how Newfoundland Power's proposal to collect the subsidy from the first 700 kWh of energy consumption in the Domestic Rate satisfies the Board's goal of placing the subsidy more equally on other forms of energy than the present situation.

A. At the present time, the subsidy is collected uniformly across all kWh consumption in the Domestic class. Because the subsidy is collected as a 0.57 cent/kWh adder to all Domestic consumption, customers who heat with wood or oil (and consequently use less electrical energy) pay less of the subsidy then those who use electric heat. The following table shows the amount of subsidy paid at various kWh consumptions:

Monthly kWh Consumption	Subsidy Paid/Month
250	$1.43
500	2.85
700	3.99
1000	5.70
1500	8.55
2000	11.40

Presumably the customers using less than 700 kWh/mo are not using electric heat and are using oil or wood to heat their homes. Due solely to the choice of heating fuel, they are escaping the payment of an equitable share of the subsidy. As the Board pointed out, this is neither fair, nor efficient.

Revised

Under Newfoundland Power's proposal, the subsidy would be spread only over the first 700 kWh of consumption in the Domestic class. Under that proposal, the adder would be 1.190 cents per kWh. This gives the following subsidies paid by various consumptions.

kWh Consumption	Subsidy Paid/Mo.
250	$2.98
500	5.95
700	8.33
1000	8.33
1500	8.33
2000	8.33

Newfoundland Power's proposal better accomplishes the Boards goals of collecting the subsidy more equitably from electric customers regardless of their choice of heating fuel.

Q. Did you consider simply assigning the rural rate subsidy to the fixed charge?

A. Yes. Assigning all of the subsidy directly as a fixed charge actually accomplishes the basic efficiency goals better than assigning the rural rate subsidy to the first 700 kWh block in the domestic class, but it also has some undesirable effects. It gives a higher increase to the smaller users than Newfoundland Power's proposal.

Revised

either class non-coincident peak at primary level or class coincident peak at the transmission level, the Bary curve relationships for class coincidence versus customer load factor should hold for these costs. I have applied the relationships from the Bary Curve and the cost of service study, and get the following table showing appropriate energy-only costs for low load factor customers in Rate 2.2. Applying the low load factor relationships from the Bary curve, we see the results in the table below.

Newfoundland Power's Cost of Serving Customer's Rate 2.2 by Load Factor

Load Factor (%)	Bary Curve Coincidence (%)	Demand Costs ($/kWmo.)	Demand Plus Energy Costs (cts/kWh)
5	23	3.68	13.09
10	47	6.53	11.88
15	62	8.32	10.42
20	72	9.51	9.26
30	82	10.70	7.51

Supporting analysis for this table is shown in Exhibit LBB-4.

The final demand plus energy costs in this table also include the 2.09 cents/kWh of unit energy costs in the Rate 2.2 class. If full demand and energy costs were assigned to the energy charge for low load factors, the rate for 2.2 would be around 14 cents/kWh at load factors of 5% and less for load factors above that. Newfoundland Power's proposal to allow these rates to be capped at 14 cents/kWh for energy only therefore appears reasonable.

Revised

There are also several non-cost based reasons for offering a reasonably priced energy-only limit to very low load factor customers in Rate 2.2. First, most of the low load factor customers in the class are still relatively small demand customers. This means that it may not be economically feasible to install equipment to control their demand. Second, they do not usually understand demand and demand billing. This means many will either convert from electric heat or become perpetually disgruntled customers. Neither situation is desirable.

Similar calculations to those done above for Rate 2.2 would yield lower energy only rates for Rates 2.3 and 2.4. Since the unit demand cost is lower ($10.10/kVA per month for 2.3 and $10.41/kVA per month for 2.4 versus $10.46/kW per month for 2.2) the resulting energy-only rate in Rates 2.3 and 2.4 would be slightly less than 14 cents/kWh, but not appreciably less. Since Newfoundland Power has traditionally set these rates equal, I see no reason not to continue that practice.

Q. Are you aware of any other Canadian utilities who limit the maximum effective charge per kWh to low load factor customers in this way?

A. Yes. Nova Scotia Power has limits in their small industrial and commercial rates similar to the one proposed by Newfoundland Power. Nova Scotia has a $4.75/kVA demand charge and a 6.20 cents/kWh energy charge (for customers with load factors below 30%) in their small industrial rate and a $7.17/kW demand charge and a 7.6 ¢/kWh energy charge (for customers with load factors below 28%) in their small commercial rate. They also have the following clause in both rates:

Revised

"The Maximum charge per kWh will be that for a billing load factor of 10%, except that the minimum monthly bill shall not be less than $12.60"

The effective rate at 10% load factor for a small industrial rate is 12.06 ¢/kWh at a 90% power factor, and for their small commercial rate is 17.39 ¢/kWh.

Alberta Power also offers an energy-only option, electable by the customer, in its small general service class 21 (below 50/kW). That option allows the customer to choose either a demand and energy rate of $4.05/kW and 7.53 cents/kWh for the first 200 kWh per kW of billing demand and 3.38 cents per kWh for the remainder, or elect an energy only rate of 16.0 cents/kWh for the first 50 kWh per kW (7% load factor) and 8 cents/kWh for all excess energy over that amount.

Q. Mr. Brockman, do you have any concluding comments?

A. Yes. Rate design is a complex process that must balance competing objectives. Changing one item to achieve a particular objective may negatively impact on another objective. This Newfoundland Power rate proposal makes a number of important changes in rate structure which further the overall objectives of fairness and efficiency with reasonable balance.

Resume of Larry B. Brockman

Mr. Larry Brockman is an Executive Vice President with EDS's Management Consulting Services (MCS). Mr. Brockman specializes in providing clients with regulatory and litigation assistance and strategic planning counsel. He has over 20 years of utility industry experience. Since joining EMA, the utilities division in 1985, examples of his work have included:

Experience:

Competitive market position studies for electric utilities and power marketers, including evaluations of market clearing prices versus embedded rates, including potential stranded investments in future US deregulated markets.

Independent reviews of the least-cost supply and demand side plans of several major electric utilities and preparation of independent resource plans for use in least-cost planning and cogeneration avoided cost proceedings.

An anti-trust case involving all phases of power supply planning, from load forecasting to final projections of future costs and damage calculations to a rural electric cooperative for a 40-year historical and 20 year projected time period.

Development of techniques and procedures for evaluating Independent Power Producers' bids for a major Northeastern electric utility to ensure that winning bids will be consistent with the utility's integrated resource plan.

Strategic reviews of bulk power supply markets for use in merger and acquisition studies and creation of successful negotiating postures for purchases and sales in these markets.

Development of testimony and case strategy for a FERC hearing on the economicl Consequences to the electric industry from abrogation of long-range bulk powerl contracts.

Expert Testimony on behalf of United States and Canadian clients concerning merger benefits, least-cost planning, regulatory policy, cost-of-service and rate design, and the links between rate design and least cost planning.

Instructor and co-developer of two internationally recognized courses on "Utility Regulation and Rate Design" and "Least Cost Planning" sponsored by Public Utilities Reports, Inc. and The Management Exchange.

Prior to joining EDS, Mr. Brockman was the Assistant Director of the Electric and Gas Department for the Florida Public Service Commission. He had responsibilities for supervising and guiding 48 employees engaged in all phases of electric and gas utility regulation. Major projects managed by Mr. Brockman included: Testimony and final recommendations to the Commission on numerous rate cases for all major electric and gas companies in Florida including prudence evaluations of utility capital expansion plans, determination of rate base, allowable expenses, total revenue requirements, class cost-of-service, and final rate design.

Establishment of and administration of the State's Annual Planning Workshop involving evaluations of utility load forecasts,demand side management and conservation programs, and investigations of the cost effectiveness of resource expansion plans. Evaluations and recommendations to the Commission on various generic policies and procedures for best accomplishing numerous state and federal energy goals.

Mr. Brockman also has experience as a system planning engineer with municipal electric systems in Florida In this capacity he: Performed a comprehensive Long-Range Transmission and Distribution Study for the City of Gainesville, Florida, including examination of the cost effectiveness of new transmission lines, substations, voltage conversions, reconductoring and power factor correction. Mr. Brockman conducted public hearings and testified before the City Commission on the resulting proposed transmission lines and substation construction.

Conducted numerous studies for Jacksonville Electric Authority at the state and local level of transmission system adequacy and reliability, from both a steady state and transient stability perspective, and served as chairman of the Florida Electric Coordinating Group's Long Range Transmission Task Force.

Education:

In 1973, Mr. Brockman received a B.S. degree in Engineering from the University of Florida. He subsequently did graduate work in electric power systems and economics at the University of Florida in 1977 and 1978. From 1979 to 1980, he served as Outside Consultant to the Public Utilities Research Council. Mr. Brockman co-authored with Dr. Sanford V. Berg, a study on Marginal Cost Ratemaking that was published by the Public Utilities Research Council.

Expert Witness Regulatory Appearances:

Florida Public Service Commission 1981 - Florida Power and Light Company Rate Case, Docket No. 810002. Testified on behalf of Commission Staff concerning Cost of Service.

Florida Public Service Commission, 1983 - City of Tallahassee Surcharge for Areas Outside City. Testified on behalf of Commission Staff concerning marginal and embedded costs and whether

City of Tallahassee had submitted adequate proof to support its electric rate surcharge for customers served outside the City.

Florida Public Service Commission, 1987 - Gainesville Gas Company Rate Increase. Testified on behalf of Gainesville Gas Company on cost of service and rate design.

Florida Public Service Commission, 1988 - West Florida Natural Gas Company. Testified on behalf of West Florida Natural Gas Company on Cost of Service and Rate Design, and the need for a flexible industrial gas rate to meet competition from alternate fuels.

Oklahoma Corporation Commission, 1989 - Avoided Cost Proceeding Cause Nos. PUD 000345 and PUD 000776. Oral testimony on behalf of Oklahoma Gas and Electric Company, concerning appropriate computer modes for Least Cost Planning.

Nova Scotia Board of Commissioners of Public Utilities, 1989 - In the Matter of Application of Nova Scotia Power Corporation for Approval of Certain Revisions to its Rates, Charges and Regulations. Testified on behalf of Nova Scotia Power Corporation concerning Cost of Service and Rate Design.

Nova Scotia Board of Commissioners of Public Utilities, 1990 - In the Matter of Nova Scotia

Power Corporation for Approval of Certain Revisions to its Rates, Charges and Regulations.

Testified on behalf of Nova Scotia Power Corporation on Cost of Service, Rate Design and Least Cost Planning.

Nova Scotia Board of Commissioners of Public Utilities, 1993 - In the Matter of: the Nova Scotia Power Incorporated and a Hearing Relating to Cost of Service and Rate Design. Testified on behalf of Nova Scotia Power on Cost of Service and Rate Design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1990 - Testified in intervention on behalf of Newfoundland Power and Light, Ltd. concerning the need for integrated resource planning, and cost of service and rate design for Newfoundland and Labrador Hydro's request for general rate relief

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992 - Testified in intervention on behalf of Newfoundland Power and Light, Ltd. concerning cost of service and rate design for Newfoundland and Labrador Hydro.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1993 - Generic investigation on Cost of Service and Rate Design. Testified on behalf of Newfoundland Power and Light Company, Ltd.

Public Service Commission Colorado, 1994 - Testified on appropriate use of computer planning models in Public Service Company of Colorado's IRP case.

Federal Energy Regulatory Commission, 1994 - Testified on behalf of Central and Southwest Services, Inc. (CSW) concerning production cost merger benefits for a proposed CSW - El Paso merger. Docket Nos. EC94-7-000 and ER94-898-000.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1995 - In the Matter of an Inquiry into issues relating to the supply of electricity to isolated rural areas of the Province of Newfoundland. Testified on behalf of Newfoundland Power concerning economic effects of electric subsidies to isolated rural areas.

Nova Scotia Board of Commissioners, 1995 - In the matter of a request for an increase in rates of Nova Scotia Power Incorporated. Testified on behalf of Nova Scotia Power concerning rate design, its relationship to IRP and competition.

NEWFOUNDLAND LIGHT AND POWER CO. LTD.
PROJECTION OF SYSTEM MARGINAL COSTS FOR LOADS ON DISTRIBUTION SECONDARY
Annual Carrying Charges for Investment Costs based on Economic Carrying Charge
(Mid-Year Current Dollars)

	DEMAND RELATED COSTS [1]							SHORT-RUN ENERGY COSTS[1]			
Year	Generation Capacity ($/kW-Yr)	NLH TMS Common ($/kW-Yr)	NLH TMS Spec Ass. ($/kW-Yr)	NP TMS ($/kW-Yr)	NP Dist. ($/kW-Yr)	Total Capacity ($/kW-Yr)	Total Capacity[2] (¢/kWh)	Holyrood Energy (¢/kWh)	C.T. Energy (¢/kWh)	Weighted Total Energy[3] (¢/kWh)	Total Marginal Cost (¢/kWh)
1996	17.7	9.5	1.8	8.3	35.4	**72.6**	**1.7**	3.8	9.3	**4.1**	**5.8**
1997	12.0	9.7	1.9	8.5	36.1	**68.1**	**1.6**	3.9	9.5	**4.2**	**5.8**
1998	9.1	9.7	1.9	8.5	36.2	**65.4**	**1.6**	3.9	9.6	**4.2**	**5.8**
1999	12.3	9.8	1.9	8.5	36.3	**68.7**	**1.6**	3.9	9.6	**4.2**	**5.9**
2000	21.6	9.7	1.8	8.4	35.9	**77.5**	**1.8**	3.9	9.5	**4.2**	**6.0**

1 - Includes losses to the distribution secondary.
2 - Calculated using NP system load factor of 0.48.
3 - Assumes C.T. production at 5%

500 kilowatts but including a few as low as 100 kilowatts, and averaging around 2,500 kilowatts.

Traction covers the individualized supplies of 60 cycle polyphase and 25 cycle single or polyphase services at high tension voltages to electrified railways and railroad systems.

Street Lighting covers the individualized supply of service for street illumination of a series or multiple type, where the utility either owns or does not own the utilization facilities.

Sales to Other Electric Utilities covers individualized firm service supplies from the bulk transmission system to neighboring utilities for resale.

Interdepartmental Use covers the supply of service to other departments of the utility.

The basic determinants of classification in this model of the load structure are (a) the physical character, that is, voltage level, of service supply and (b) the general nature for which the service is used. Accounting and rate classifications are made to fit the structure of this model, rather than the other way around.

EMPIRICAL RELATIONS

The quest for knowledge and understanding of the behavior of the load structure cannot stop with the class loads. To understand the behavior of the class, it is necessary to understand what goes on within it. To obtain that knowledge, means must be found for establishing for each general class the probable trends that are going on in the load behavior of its individual elements, arranged in groups according to the significant controlling characteristic under which the particular class is administered in the utility's operations.

There are two such controlling characteristics of significance on a modern electric utility system: the individual customers' energy use; and, the individual customers' monthly load factors by billing demand intervals. The former applies in our model primarily to customers of the residential class, the latter, to the manufacturing and nonmanufacturing classes.

Energy versus Diversified Demands. Figure 11 depicts relationships between customers' annual energy use and their diversified maximum demands for average weekdays around the peak period of the residential class (more fully defined at the end of this chapter). The quantitative significance of these

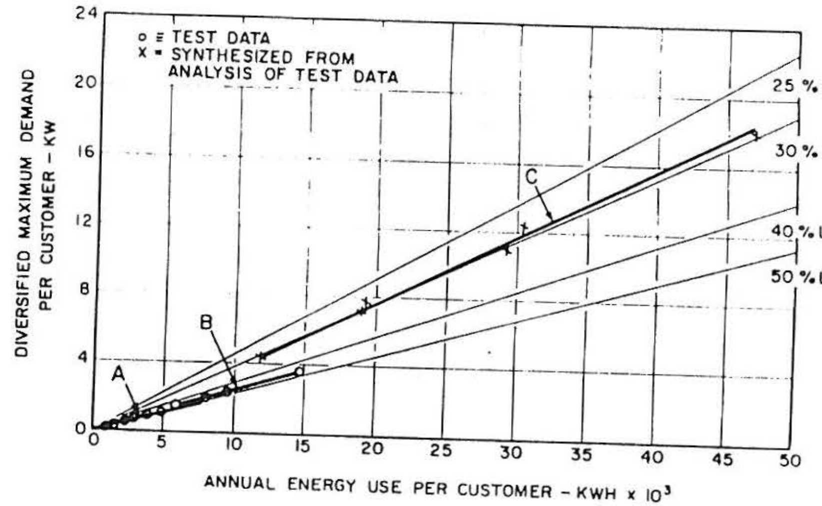

Figure 11. Illustrative relationship of energy uses *versus* average weekday diversified maximum demands of residential customers
- **A. "Base use" comprising lighting and miscellaneous appliances**
- **B. "Base use" plus electric cooking and water heating (uncontrolled)**
- **C. "All-electric home" (reflecting B plus electric cooling and heating)**

relationships is constantly undergoing changes, and undoubtedly will continue to do so in the future. It, thus, behooves us to be alert to any significant changes in these relationships. One such change looms over the horizon: studies indicate that by projecting data into the conditions of an all-electric home, which would include electric space heating and air conditioning (under uncontrolled methods of operation), the energy *versus* group demand relationship, shown in Figure 11, will not only move into a much higher energy and diversified maximum demand region, but at the same time, into a band of much lower annual load factors than is obtained now with the load of a full-use home, before the introduction of electricity for the performance of the heating and cooling jobs.

Coincidence Factors versus Load Factors. Figure 12 depicts an empirical relationship between group coincidence

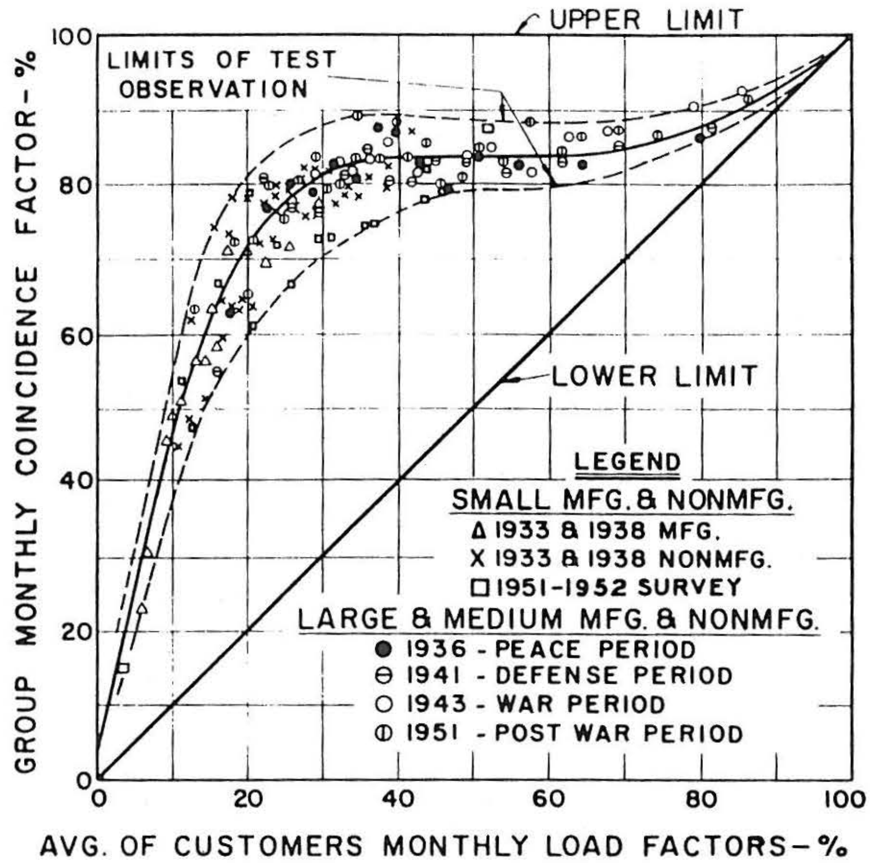

Figure 12. Empirical relationship between coincidence factors and load factors—based on integrated 30-minute demands in December for groups of 30 customers

factors for customers of the manufacturing and nonmanufacturing classes and individual customers' monthly load factors. This relationship and its underlying theory have been described in detail by me in 1945[2] and were first outlined in my 1937 presentation to the Association of Edison Illuminating Com-

[2]Constantine W. Bary, "Coincidence-Factor Relationships of Electric Service Load Characteristics," *AIEE Transactions*, LXIV (1945), 623.

panies (AEIC).[3] It has been studied in a thorough manner and verified first in 1939 by a subcommittee, F. M. Terry chairman, of the Special Committee on Load Studies of AEIC,[4] and then again in 1952 by a subcommittee, B. P. Dahlstrom chairman, of the Load Research Committee of AEIC.[5] H. E. Eisenmenger rationalized and verified the shape of the empirical curve in a classical manner, from mathematical considerations, in his 1939 paper before the 55th Annual Meeting of AEIC.[6] It has become known as the Second Law of Load Diversity,[7] or the "Bary" curve. It provides conveniently the means for obtaining the probable diversified maximum demands per customer for a given set of customers' monthly energy uses and their noncoincident maximum demands, which are the necessary ingredients for computing customers' load factors.

It will be noted from the actual test data shown, that over nearly two decades of observations, covering pre-war, defense, war, and post-war conditions, the probable average relationship of test observations remain unaltered.

(Recently completed studies of 1961 data on load patterns of customers of the manufacturing and nonmanufacturing class, which resulted in 118 test-observations spread over a wide range of monthly load factors, again substantiate the qualitative and quantitative nature of the relationship between monthly coincidence factors and load factors established for the month

[3]Constantine W. Bary, "Economic Significance of Load Characteristics as Applied to Modern Electric Service," Minutes, 53d Annual Meeting (New York, Association of Edison Illuminating Companies, 1937, unpublished).

[4]"Report of Subcommittee on Coincidence Factors of the Special Committee on Load Studies of the AEIC," Minutes, 55th and 56th Annual Meetings (New York, Association of Edison Illuminating Companies, 1939 and 1940, unpublished).

[5]"Report of General Subcommittee on Nonmanufacturing and Manufacturing Customers of Load Research Committee of the AEIC," Minutes, 69th Annual Meeting (New York, Association of Edison Illuminating Companies, 1953, unpublished).

[6]H. E. Eisenmenger, "Study of the Theoretical Relationship between Load Factor and Diversity Factor," Minutes, 55th Annual Meeting (New York, Association of Edison Illuminating Companies, 1939, unpublished).

[7]The first law of load diversity is the relationship which exists between group coincidence factors and the number of customers in the group, described in my 1945 AIEE paper (see footnote 2).

of December. From a recent compilation of equally comprehensive data for customers of this class for the 1961 summer period, a similar relationship has been established for the warmest month which reflects heavy use of air conditioning equipment. The qualitative nature and the quantitative magnitudes of this relationship are virtually the same as for the month of December, and the new test-observations follow the patterns of dispersion outlined by the limits of observation shown in Figure 12.)

This relationship can be considered, therefore, as of a fundamental nature in the general behavior of electric loads. But being of an empirical nature the following qualifications must be kept in mind:

1. It is an empirical relationship and is based on the conditions and experience of one utility system supplying a given community. Other communities with different population habits, different definition as to what constitutes a class of service, different weather and other climatic conditions, may differ in the actual magnitudes of the coincidence factors shown throughout the entire load-factor range.

2. The relationship is confined to consumers of substantially the same size, taking the same class of service, operating at the same load factors, and always taken in sufficient numbers for each type, size, and load factor to produce representative results on a coincidence factor of the group. It is obvious that, unless these qualifications are observed fully, different coincidence factors may be obtained.

3. The coincidence factors obtained from Figure 12 are those for individual consumers within a group applied to monthly conditions. There will be additional coincidence factors between different groups of any one class of service, for longer periods than a month, and between different classes of service of a system.

INTERGROUP AND INTERCLASS COINCIDENCE FACTORS

Experience with the two probable relationships just described has shown that no matter which of the controlling characteristics is used for arranging individual load elements by groups, the major effects of load diversity within a general class are captured and retained in the load characteristics of the groups, whether they be expressed in terms of diversified maximum demands or group coincidence factors. But it is known that additional effects of load diversity exist between groups of a given class and between classes. Their measures are called "intergroup," and "interclass" coincidence factors, respectively. Table 2 provides an indication of the general magnitudes of the intergroup, and interclass coincidence factors obtained on the illustrative utility system.

TABLE 2. ILLUSTRATIVE INTERGROUP AND INTERCLASS COINCIDENCE FACTORS

Intergroup	
Between all groups of present-day residential customers (without ranges and water heaters)	0.98
Between all groups of present-day residential customers (with ranges)	0.99
Between all groups of present-day residential customers	0.96
Interclass	
Between two classes at secondary voltage level	0.99
Between four classes at primary voltage level	0.92
Between all eight classes at production system level	0.87

The establishment of probable trend relationships between certain parameters of load characteristics at the group level of the load model is susceptible to actual determination through the statistical method of averages, because of the large mass of individual elements which can react to the laws of chance. But at other levels of the model, say that of the classes, there are so few individual things to be dealt with that, from mathematical considerations, they cannot produce trend relationships, but only individualized spot values.

Distribution of Load Diversity Benefits. Obviously, the establishment of any classification carries with it the implications regarding the applicability of load diversity benefits which exist on a modern electric utility. Much has been written on this subject in terms of the allocation of demand-related costs of an electric utility enterprise. An excellent critical résumé by P. Schiller of the better-known methods is contained in the 1943 Technical Report K/T 106 of the British Electrical and Allied Industries Research Association,[8] and an "Im-

[8] P. Schiller, "Methods of Allocating to Classes of Consumers or Load the Demand-Related Portion of the Standing Costs of Electricity Supply," Technical Report Reference K/T 106 (London, The British Electrical and Allied Industries Research Association, 1943).

NEWFOUNDLAND LIGHT AND POWER CO. LIMITED

APPLICATION OF BARY CURVE TO RATE CLASS 2.2

All Demand Cost $/billing kW.mo A (94 COS)	Portion Effected By Coinc. B	Demand Cost Effected By Coinc. $/billing kW.mo C = A X B	Average Coincidence For Class D[1]	Demand Cost Effected By Coinc. $/coinc kW.mo E = C / D	Load Factor (%) F	Bary Curve Coincidence (%) G	Demand Cost Effected By Coinc. $/billing kW.mo H = E X G	Demand Cost Not Effected By Coinc. $/billing kW.mo I = A - C	Total Demand Cost $/billing kW.mo J = H + I
10.70	90%	9.63	81%	11.89	5	23	2.73	1.07	3.80
10.70	90%	9.63	81%	11.89	10	47	5.59	1.07	6.66
10.70	90%	9.63	81%	11.89	15	62	7.37	1.07	8.44
10.70	90%	9.63	81%	11.89	20	72	8.56	1.07	9.63
10.70	90%	9.63	81%	11.89	25	78	9.27	1.07	10.34
10.70	90%	9.63	81%	11.89	30	82	9.75	1.07	10.82

Load Factor (%) K	Total Demand Cost $/billing kW.mo L = J	Demand Cost cents/kWh M = L / (K X 730)	Energy Cost cents/kWh N (94 COS)	Total Cost cents/kWh O = N + M	Total Cost Including Rural Deficit (cents/kWh) P = 0 X 7.39%
5	3.80	10.42	1.97	12.39	13.31
10	6.66	9.12	1.97	11.09	11.91
15	8.44	7.71	1.97	9.68	10.39
20	9.63	6.60	1.97	8.57	9.20
25	10.34	5.67	1.97	7.64	8.20
30	10.82	4.94	1.97	6.91	7.42

NOTES: 1 - From Analysis of Billing Demand for Peak Month using Bary Curve Coincidence factors

Exhibit LBB-4
Page 1 of 1