A Review of the Basic Customer Charge

for

Newfoundland Power Inc.

October 3, 2002

Brockman Consulting

1. Basic Customer Charge Review

1.1 Background and Introduction

There was considerable discussion during the Newfoundland Power 1996 General Rate Proceeding, concerning the level of Newfoundland Power's basic customer charge ("BCC"). This was due to the fact that Newfoundland Power's BCC is among the highest in Canada, owing in some measure to the fact that Newfoundland Power uses a "minimum distribution system" to assign some of the distribution system costs to the customer charge. After considering the evidence, the Board, in Order No. P.U. 7 (1996-97), ordered Newfoundland Power to perform a review of its BCC. The pertinent sections of that Order read as follows:

> *The Board will order that the methodology and the resultant cost of the BCC should be revisited and that the BCC not be increased for rate classes 1.1 and 2.1 until a subsequent review has been undertaken and presented to the Board for its consideration. The review should explore methodologies other than the "minimum distribution system" in assigning distribution costs.*
>
> *The Board will approve a BCC for rate classes 2.2, 2.3 and 2.4 since there are compensating reductions which appear to treat users in these classes fairly. The resubmission of rates should retain the elimination of minimum demand and the appropriate changes in demand and energy charge and minimum monthly charge, as can be accommodated within the limits of the redesign.*
>
> ...
>
> *The Applicant shall undertake a review of the Basic Customer Charge for all classes.*

The review of the BCC ordered by the Board and updated for the 2002 General Rate Proceeding is the subject of this report.

1.2 Basic Customer Charge Theory

1.2.1 Demand Energy and Customer Charges

One of the basic tenets of good rate design is to base rates on cost. This is done to ensure fairness and efficiency. In order to better accomplish this goal, it is often convenient to break the costs down into three basic components: energy, demand and customer costs. All three of these components can be measured and billed separately.

The energy component comprises only those costs which vary with changes in energy consumption. These usually include fuel and variable operating and maintenance expense. Energy is billed on a per kilowatt hour (kWh) basis.

The demand component comprises only those costs which vary with changing demand. These usually include capital expenditures to increase the capacity of electric plant. Demand costs for large customers are usually billed on a per kilowatt month (kW month) basis. For smaller customers who do not have demand meters, it is usually added to the energy charge on a kWh basis.

The customer component includes the costs that occur simply because one is a customer and is connected to the system. These costs usually include at least the cost of the meter, service drop (service wire) and billing. Some utilities also include a portion of the distribution system between the service drop and the distribution substation. How much of these distribution system costs are included is the subject of most of the controversy concerning the BCC.

1.2.2 Other Important Effects of the Customer Charge

There are several important effects of the BCC (besides the ones mentioned in the section above) that should be considered in rate design. They are: the effects on small customers, revenue stability for the electric company, and the interactive effects between the BCC and the demand and energy charges if the utility is attempting to set prices based on marginal costs.

The BCC affects customers with low usage more dramatically than customers with higher usage because it constitutes a larger portion of their bills. Changes in energy consumption or demand have a lower impact on these customers while changes in the BCC affect customers with lower usage to a higher degree.

The level of the BCC can also have dramatic impacts on the revenue stability of the Company because the revenues from the BCC are not subject to as much fluctuation as the energy related and demand related revenues. Increased revenue stability makes it easier for the Company to manage its finances and should theoretically lead to lower cost of capital and therefore lower overall rates.

The BCC also interacts strongly with the demand and energy charges when the utility is attempting to base rates on marginal costs. That is because the marginal demand, energy and customer costs are all often above the embedded costs for each component. Since the utility must reconcile marginal cost based rates to embedded revenue requirements, one or more of these charges must be reduced when marginal costs are above embedded costs and one or more must be increased when marginal costs are lower than embedded costs. The customer charge is often thought to be the least important charge in the goal to achieve efficiency so it is often the one that gets increased or reduced in such a situation.

1.3 Methods for Calculating Customer Related Costs

There are three general approaches currently being used by utilities in North America for calculating the embedded customer related costs. They are:

1. metering, billing and collection, plus service drop costs;
2. metering, billing and collection, service drop costs, plus a share of the distribution system calculated with the minimum size method; and
3. metering, billing and collection, plus service drop costs share of the distribution system calculated with the zero intercept method.

Customer related costs can also be calculated on a marginal cost basis in much the same manner using marginal costs instead of embedded costs for each component.

In this report we examine all of the methods from the viewpoint of theoretical soundness, regulatory acceptance and the potential application of the method for Newfoundland Power.

1.3.1 Functionalization and Classification of Customer Related Costs

The process of calculating embedded cost of service starts with the functionalization and classification of all plant costs and expenses between customer, demand and energy related components. The functionalization is not usually controversial since most large utilities in the U.S. use a standardized functional system of accounting and Canadian utilities use similar systems. However, a great deal of judgment is used in carrying out the classification step.

The costs commonly associated with the customer function are dealt with in Chapters six and seven of the *1992 National Association of Regulatory Utility*

Commissioners Electric Utility Cost Allocation Manual (the "NARUC Manual"). Chapter Six deals with the classification and allocation of distribution plant (including meters and service drops). Chapter Seven deals with Classification of Customer Related Costs in the Federal Energy Regulatory Commission ("FERC") accounts 901-917 (billing, collection and information).

Table 6-1 of the NARUC Manual presents the following table showing how the distribution plant may be classified.

FERC Uniform System of Accounts	TABLE 6-1 Classification of Distribution Plant Description	Demand Related	Customer Related
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery and Equipment	X	-
364	Poles, Towers , & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems	-	-

From Table 6-1 we see that many of the distribution plant accounts can be classified as both demand related and customer related. Accounts 369 to 372, services, meters and installations and property on customer premises, are all shown as 100 per cent customer related. We have shaded that portion of the table.

Table 6-2 of the NARUC Manual deals with the classification of expenses associated with various parts of the distribution system, whose associated plant was classified in Table 6-1. As Table 6-1 shows, services, meters and installation on customer premises are generally thought to be 100 per cent customer related. The operation and maintenance expenses generally follow the classification of plant accounts and Table 6-2 shows that operation and maintenance expenses of meters, services and customer premises installations are also classified as 100 per cent customer related. We have also shaded that portion of Table 6-2.

FERC Uniform System of Accounts	TABLE 6-2 Classification of Distribution Expenses Description	Demand Related	Customer Related
	Operation		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maintenance of Street Lighting & Signal Systems	-	-
597	Maintenance of Meters	-	X
598	Maintenance of Misc. Distribution Plant	X	X

Chapter seven of the NARUC Manual deals with classifying and allocating costs associated with customer accounts, customer services, and information and sales. The manual states that "The usual approach in functionalizing customer accounts, customer services and the expense of information and sales is to assign these expenses to the distribution function and classify them as customer related."[1] This is illustrated in Table 7-1 on the following page.

[1] *NARUC Electric Utility Cost Allocation Manual,* January 1992, page 102.

FERC Uniform System of Accounts	Table 7-1 Derived From Chapter 7 NARUC Cost of Service Manual Description	Demand Related	Customer Related
	Customer Accounts Expenses		
901	Supervision	Note[1]	Note[1]
902	Meter reading expenses		X
903	Customer records and collection expenses		X
904	Uncollectible accounts	Note[2]	Note[2]
905	Miscellaneous customer account expenses		X
	Notes: (1) Classified in proportion to the sum of accts. 902-905. (2) Account 904 is sometimes classified as energy, revenue and/or customer related, since uncollectible amounts are not directly correlated to the number of customers.		
	Customer Service & Information Expenses		
906	Customer Service and Informational Expenses		X[4]
907	Supervision	Note[3]	Note[3]
908	Customer Assistance Expenses		X[4]
909	Informational and instructional advertising		X[4]
910	Miscellaneous Customer service and Information		X[4]
	Notes: (3) Classified in proportion to the sum of accts. 906-910. (4) The NARUC Cost of Service manual says that "except for conservation and load management, these costs are classified as customer related."		
	Sales Expenses		
911	Supervision	Note[5]	Note[5]
912	Demonstrating and selling expenses		X[6]
913	Advertising expenses		X[6]
916	Miscellaneous sales expenses		X[6]
	Notes: (5) Classified in proportion to the sum of accts. 911-916. (6) The NARUC Cost of Service manual states, "These costs could be classified as customer related, since the goal of demonstrations and advertising is to influence customers."		

There seems to be almost universal agreement that meters, meter reading and billing, service drops and customer premises installations should be 100 per cent customer related and therefore, included in the BCC. If one takes only the costs in the shaded rows of Tables 6-1, 6-2 and all of Table 7-1 and assigns them as customer related costs, you get the first general method of customer cost determination mentioned in Section 1.3. The second and third approaches both include the costs of the first method and add a portion of the costs shown as being both demand related and customer related in the tables.

These tables only tell us that a portion of the distribution system between the customer services and the substation may be classified as customer related. It does not tell us how much to classify that way. To evaluate how much of this plant and the associated expenses should be classified to the customer component, two basic methods have been derived. They are called the "minimum size method" and the "zero intercept method" and are dealt with in Chapter six of the NARUC Manual. The next two sections discuss these methods.

1.3.2 Minimum Size Method

One of the most fundamental ideas behind cost of service is the principle of causality. This principle states that a cost should be classified and allocated according to what makes the cost go up or down. The minimum size distribution method uses this fundamental principle by attempting to capture the costs that are incurred whenever a typical new customer is connected to the system.

The basic idea behind the minimum size method is that whenever a customer connects to the system, the utility prudently assumes that the customer will consume some minimum amount of energy and have some minimum amount of demand. In other words, that customer causes certain distribution expenses to increase and therefore ought to pay for them. Because minimum amounts of demand are assumed in the standards used by the distribution engineers to estimate the size of the system needed to serve them, it makes sense to try to capture these minimum amounts in the basic customer related costs. To quote the NARUC Manual "The minimum size method involves determining the minimum size pole, conductor, cable, transformer and service that is currently installed by the utility."[2] The cost of this minimum amount of plant and the expense necessary to maintain it, are then assigned to the customer function in the mixed plant accounts shown in Table 6-1 and the remaining costs in these accounts are classified as demand related. The expense accounts shown in Table 6-2 follow these assignments in the same proportions.

Newfoundland Power has for many years used the minimum size method for determining the amount of distribution system costs associated with the customer component. Newfoundland Power and others often call their use of the minimum size method the "minimum distribution method" but we have adopted the NARUC terminology here. The details of Newfoundland Power's calculations shall be discussed in Section 1.6.

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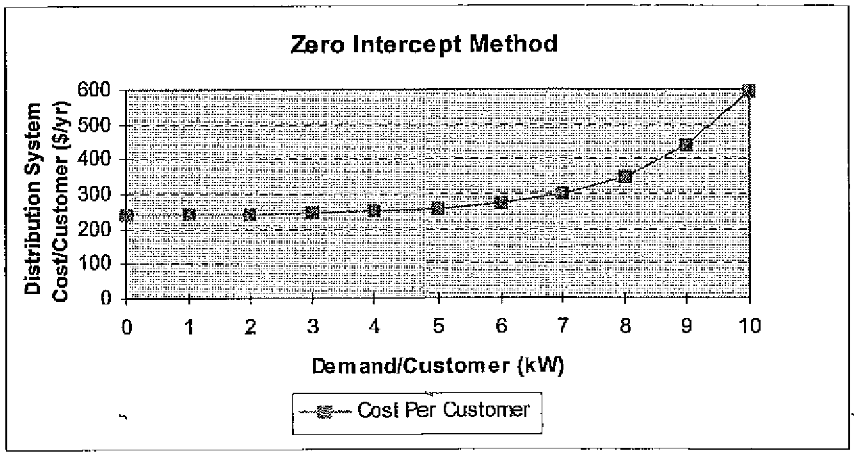
[2] *NARUC Electric Utility Cost Allocation Manual*, January 1992, page 90.

The minimum size method clearly has a sound causality basis because if the utility did not assume some level of demand for a new customer, the system would rapidly experience severe problems as the customers used power. Because the standards exist, the effect of a new customer connecting to the system is to cause the cost of the minimum system to be increased whether the customer uses any electricity or not.

1.3.3 Zero Intercept Method

Another method for calculating what portion of the distribution system costs should be attributed to the customer related function is the "zero intercept method". The essence of this method is the idea that if we plot the cost of providing a distribution system for various levels of demand that might be assumed to occur on it, we would find a line that decreases as the demand decreases and this line can be extrapolated to cross the cost axis at zero demand. Thus, the name "zero intercept". This concept is illustrated in the figure below.



In the example above, the zero intercept (and the cost calculated per customer) for this portion of the distribution is about $240 per kW per year. This amount would then be converted into a monthly minimum amount of $20 per month and included in the BCC.

1.4 Customer Related Costs on the Newfoundland Power System

1.4.1 Newfoundland Power's BCC

Newfoundland Power has among the highest residential and small general service BCC in Canada. This is illustrated in Table 1 and Table 2 that provides a comparison of the BCC for Canadian utilities from surveys that were conducted in March 1998, and August 2002.

TABLE 1. – March 1998 Survey of Canadian Basic Customer Charge (BCC)		
Utility	**BCC Residential**	**BCC Small General Service**
Newfoundland Power	$16.56	$18.85
Nova Scotia Power	$10.50	$12.60
New Brunswick	$14.33 (urban) $15.80(rural)	$14.33
Maritime Electric	$15.76 (urban) $17.38(rural)	$15.76
Quebec Hydro	$11.71(38.5¢/day)	$11.49
Ontario Hydro	$10.90 (urban) $14.60 (rural high) $16.45 (rural normal)	$12.40 (urban) $27.95 (rural)
Manitoba Hydro	$6.25 (Winnipeg) $7.63 (medium density) $13.65 (low density)	$14.90 (Winnipeg) $16.23 (medium density) $18.56 (low density)
Sask Power	$9.87+$2.00 (urban) $11.86+$2.00 (rural)	$8.98+$4.95 (urban) $12.24+$4.95 (rural)
Alberta Power	$11.90	na
TransAlta	$11.90	na
West Kootenay Power	$13.34/2months	$18.30/2months
BC Hydro	$6.92/2 months	$8.29/2 months

Table 2. – August 2002 Survey of Canadian Basic Customer Charge (BCC)		
Utility	**BCC** **Residential**	**BCC** **Small General Service**
Newfoundland Power	$16.81	$19.13
Nova Scotia Power	$10.50	$12.60
New Brunswick	$15.79 (urban) $17.30(rural)	$15.79
Maritime Electric	$17.37 (urban) $19.03(rural)	$17.37
Quebec Hydro	$11.70/30 days	$11.67/30 days
Ontario Utilities:		
Hydro One Networks	$12.05 (urban) $16.20 (rural high) $21.70 (rural normal)	$13.33 (urban) $31.96 (single phase) $40.58 (three phase)
Toronto Hydro Electric System	$14.03/30 days	$18.59/30 days
Hydro-Ottawa	$6.85	$7.80
Manitoba Hydro (All Regions)	$ 6.25 <200 Amps $12.50>200 Amps	$14.90 (single phase) $20.86 (three phase)
Sask Power	$13.16 (urban) $17.41 (rural)	$18.34 (urban) $23.95 (rural)
Alberta Utilities:		
ATCO Electric	$22.90	$13.64
EPCOR – City of Edmonton	$12.98	$10.28
- Outside of Edmonton	$19.21	na
ENMAX	$15.61/30 days	$23.36/30 days
BC Utilities:		
BC Hydro	$6.92/ 2 months	$8.29/ 2 months
Aquila Networks Canada	$19.48/ 2 months	$21.44/ 2 months

As Table 1 and Table 2 show, the BCCs for New Brunswick, Maritime Electric, Ontario, Sask Power, and Alberta have increased since 1998, and are now closer to the charges of Newfoundland Power. The charges for Nova Scotia, Manitoba and BC Hydro have remained the same.

Newfoundland Power's relatively high residential and small general service BCC has been attributed, in part, to the minimum distribution system calculations.[3] The use of the minimum distribution (size) system method certainly contributes to the level of Newfoundland Power's customer related costs, as shown in their cost of service study. However, the final rate set for the BCC does not recover all of the customer related costs shown in the cost of service study referenced in Section 1.6.

A recent confidential survey by Newfoundland Power (discussed in Section 1.5) revealed that all the Canadian utilities in the list had customer related costs in their cost of service studies that were higher than what they are charging. For example, the cost of service for residential customers reported by these utilities in 1998 ranged between $10.77 and $30.00 per month with seven utilities with average customer costs above $15.80 per month. However, as Table 1 above shows, the surveyed utilities were only charging between $3.46 and $17.38 per month for the Domestic BCC.

1.4.2 Recent Criticisms of Newfoundland Power's BCC

As I have already mentioned, Newfoundland Power's BCC (or at least the minimum distribution system aspect of it) has been criticized by the Board's consultant, Dr. J.W. Wilson. Dr. Wilson, at the 1996 General Rate Proceeding of NP, criticized Newfoundland Power's method on several grounds. First he states (page 37 of his July 1996 evidence) that the minimum distribution system is flawed because investments in the distribution lines "are not customer specific facilities that are causally attributable on the basis of customer counts." He also faults the minimum distribution system because of its effects on smaller customers which he says overcharges them. He goes on to state (page 44 of his July 1996 evidence) that the minimum distribution system "attributes costs to a rate category (customer charges) that provides no meaningful price signal to most customers."

I do not find Dr. Wilson's arguments against the way Newfoundland Power calculates the customer related costs to be persuasive. If minimum standards exist (and they do), then when customers connect to the system they clearly cause at least the minimum costs associated with the standards to be incurred and the basic principle of

[3] Dr. J.W. Wilson, the Board's witness, stated at page 14, lines 16-18, of his July 1996 evidence in the Newfoundland Power rate case, "NL&P's customer charges are substantial - largely because the costs of a 'minimum distribution system' are classified as customer costs rather than service costs."

cost causality says they should be assigned those costs. The fact that small customers may not have the amount of demand included in the standards does not mean that they are being any more unfairly treated than if we asked the other customers in their energy charges to pay for the minimum cost of connecting the small customers.

Dr. Wilson's final argument that the minimum distribution system "attributes costs to a rate category that provides no meaningful price signal to most customers" is a rate design issue and should not be confused with cost causation. In general, I feel it is better to keep cost of service issues separate from rate design. What Dr. Wilson is alluding to here is his belief that the marginal costs of energy and demand on the island are so much greater than the embedded costs that a reconciliation of revenues would require reducing the BCC to achieve efficiency. In fact, as I discuss in the curtailable service option review, the marginal costs on the island are highly uncertain at this time and it is not clear such a conclusion can be drawn.

The arguments for and against the inclusion of a minimum distribution system are old arguments in the regulatory arena and to some extent an exercise in frustration because there simply is no "correct" answer to the question of how much of the distribution system should be allocated to the customer function. Bonbright alludes to this in the quote provided on page 38 of Dr. Wilson's testimony where he says "The really controversial aspect of customer cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) distribution system..."

The reason the area is "really controversial" is because reasonable people disagree on it. If one talks to the distribution engineers designing the electric system, many will tell you it is their opinion that there is clearly a customer related component to the distribution system. This belief is primarily driven by the minimum standards requirements or regression analysis of the type done in the zero intercept analysis. If you talk to economists, some will tell you they do not believe in the minimum distribution system while others do.

The extent of regulatory acceptance of the minimum distribution system shows the same controversy. It is reflected in the cost of service studies across Canada, which show that not all the costs are reflected in the rates.

1.5 Survey of Canadian Practices on the BCC

In order to assess the relative position of Newfoundland Power's customer related charges with respect to other Canadian utilities, we conducted a survey of Canadian utilities in 1998. The survey primarily focused on the BCC for residential and small general service customers since the BCC is relatively less important for larger customers and therefore not as controversial. The following questions concerning the BCC were asked by telephone:

1. What is included in the basic customer charge for customer classes in your province?
2. Is any of the distribution system beyond the meter and service drop included in the basic customer charge for these classes for utilities in your province? If so, how is it determined?
3. Do utilities in your province use the minimum distribution system concept? If so, how is it determined?
4. How are the distribution system costs classified and allocated in your province?
5. Do the basic customer charges fully recover the customer related costs for these classes of customers?
6. If the basic customer charge does not cover the costs, is the gap closing as you continue to have rate cases?
7. How do you think retail competition will change the design of the customer charges for these classes in your province?

Many of the respondents wanted to remain anonymous; therefore the results are discussed in summary fashion only. Nine of the 10 Canadian utilities responding to questions 1 and 2 include distribution system costs in their customer related costs in addition to the meter, billing, service drop and customer information costs. Five of nine utilities used the minimum distribution system. Three used the zero intercept method, and one utility used neither method (i.e., responses to questions 3 and 4). Eight of the nine utilities that responded to question 5 on whether the BCC recovered all the costs said that it did not. There were few responses to questions 6 and 7.

In September 2002, Fosters and Associates provided Newfoundland Power with a summary of a survey they conducted on cost of service methodologies used by electric utilities in Canada. The results of the Fosters' survey supported the conclusions of the survey conducted in 1998.

In Order No. P.U. 7 (2002-2003), the Board accepted the use of the zero intercept method to classify a portion of Hydro's distribution system costs as customer related. The splits used by Hydro and those proposed by the Company are shown in Table 3.

Table 3
Distribution Costs Breakdowns

	Demand Per cent	Customer Per cent
Newfoundland Power	68.1	31.9
Newfoundland & Labrador Hydro[1]	72.5	27.5

[1] Calculated from the Hydro 2002 forecast cost of service filed pursuant to Order No P.U. 7 (2002-2003).

The comparable results for Hydro and Newfoundland Power also support the conclusion that the method used by the Company to determine the customer related portion of the distribution system is reasonable.

1.6 Newfoundland Power's Minimum Distribution System Studies

The results of the minimum distribution system study and zero intercept analysis are used to derive the percentage of the distribution system costs (i.e., between the service drop and the distribution substation) that are to be classified as demand related vs. customer related.

The results of the latest minimum distribution size system study, in addition to a zero intercept study of transformers, performed by Newfoundland Power are attached as Appendices A and B. Table 4 below summarizes the results. I have reviewed these studies and find no fault with the calculations.

Table 4
Classification of Distribution System Costs

	Customer Related	Demand Related
Conductor Poles and Fittings		
Distribution Poles and Fixtures	41%	59%
Conductors –Urban Construction	22%	78%
Conductors – Rural Construction	16%	84%
Total Conductor Poles and Fittings	33%	67%
Distribution Transformer Costs	27%	73%

Newfoundland Power is recovering 100 per cent of the customer related costs associated with metering, billing, service drop and customer information for the domestic and small general service classes (see the following Table 5). The BCC for the remaining classes do not collect all of the metering, billing, service drop and customer information costs. For the residential and small general service class, approximately 60% per cent of the cost associated with the minimum distribution system is collected.

Table 5. – 2001 COS Customer Cost vs. BCC

Class	Unit Cost of Metering, Billing, Service and Customer Information	Unit Cost Including Minimum Distribution System	Current Newfoundland Power Basic Customer Charge[1]	Percentage of Minimum System Recovered Beyond Service Drop
Domestic	$11.87	$19.29	$16.42	61%
General Services				
Rate Class 2.1	14.31	21.72	18.69	59%
Rate Class 2.2	30.67	38.08	20.35	0%
Rate Class 2.3	97.16	104.36	91.61	0%
Rate Class 2.4	183.66	189.15	183.23	0%

1 September 2002 rates exclusive of RSA and MTA Adjustments.

Given the evidence presented on the extent of acceptance of the minimum distribution system, I do not feel this recovery of basic customer costs is excessive and recommend no changes at this time. However, Newfoundland Power should consider increasing the BCC for the general service classes in which the BCC does not collect all of their metering, billing, service drop and customer information costs.

1.7 Conclusions and Recommendations

After reviewing the evidence on the level, acceptance and derivation of the BCC for Newfoundland Power and other utilities in Canada, I have arrived at the following conclusions and recommendations.

1. It is important to have basic customer charges to ensure fairness and revenue stability.

2. There seems to be almost universal agreement that at least the cost of metering, billing, customer information and service drop costs should be included in the customer related costs in the cost of service study.

3. Methods for calculating how much of the cost of the distribution system between the service drop and the distribution substation should be included in customer related costs are controversial and there seems to be no universally accepted way to do it.

4. For Domestic customers, Newfoundland Power's BCC is among the highest in Canada. However, in the past few years the BCC of some other utilities have increased significantly and some utilities now have a higher BCC than Newfoundland Power.

5. Most utilities in Canada use some form of minimum distribution system method to derive customer related costs. Newfoundland Power's customer costs are reasonable compared to other Canadian utilities.

6. A survey of Canadian utilities showed that the BCC generally does not recover all the customer related costs derived from their cost of service studies, suggesting that regulators consider other factors when setting this charge.

7. The minimum size system and zero intercept method used by Newfoundland Power in deriving the portion of the distribution system costs to be treated as customer related is based on the generally accepted principle of causality and is widely used across Canada.

8. Newfoundland Power's BCC for residential and small general service classes recovers 100 per cent of the cost of metering, billing, customer information and service wire costs. In addition, the charges recover approximately 60% of the customer related cost for each class attributable to the cost of distribution system.

9. The Company's current method of calculating its customer related costs is within the mainstream of Canadian electric utility practice. There does not appear to be any substantial justification for changing that methodology or the customer cost recovery at this time.

10. Newfoundland Power should consider increasing the BCC for the general service classes that presently do not collect all of their meter, billing and customer service costs in the BCC.

NEWFOUNDLAND POWER INC.

2001 MINIMUM SYSTEM ANALYSIS

NEWFOUNDLAND POWER INC.

MINIMUM SYSTEM ANALYSIS

The minimum system analysis is based on two components

- Poles and Fixtures
- Conductors

Minimum System Costs for Poles and Fixtures (Urban or Rural)

A	Estimated number of NP distribution line poles[1]	215,631	
B	Estimated cost of minimum system pole[2]	$755	per pole
C	Estimated number of NP & NTC joint use distribution line poles[1]	250,555	
D	Estimated cost of minimum system pole structure[2]	$79	
E	Total Distribution poles & fixtures account inflated to 2001 dollars[3]	$444,482,522	
F	Minimum System Pole Costs (Line A times Line B)	$162,801,405	
G	Minimum System Pole Structure Costs (Line C times Line D)	$19,793,845	
	% Minimum System (classified as a Customer Cost) (Line (F+G) / Line E)	41.08%	

Minimum System Costs for Conductor (Assuming Urban Constuction)

H	Estimated number of feet of conductor [4]	52,325,260	ft.
I	Estimated cost of minimum system conductor[2]	$0.87	/ft.
J	Total distribution conductor account inflated to 2001 dollars[3]	$210,627,955	
K	Minimum System Costs (H X I)	$45,522,977	
	% Minimum System (classified as a Customer Cost) (Line K / Line J)	21.61%	

Minimum System Costs for Conductor (Assuming Rural Constuction)

L	Estimated number of feet of conductor[4]	52,325,260	ft.
M	Estimated cost of minimum system conductor[2]	$0.63	/ft.
N	Total distribution conductor account inflated to 2001 dollars[3]	$210,627,955	
O	Minimum System Costs (L X M)	$32,964,914	
	% Minimum System (classified as a Customer Cost) (Line O / Line N)	15.65%	

NEWFOUNDLAND POWER INC.

Summary of Results

	Minimum System Costs	
	Poles and Fittings - Urban (Line F + Line G)	$182,595,250
	Conductors - Urban (Line K)	$45,522,977
	Total Minimum System - Urban	$228,118,227
	Poles and Fittings - Rural (Line F + Line G)	$182,595,250
	Conductors - Rural (Line O)	$32,964,914
	Total Minimum System - Rural	$215,560,164
P	Weighted Minimum System assuming 25% Urban, 75% Rural[5]	$218,699,680
Q	Total Distibution Poles, Fixtures and Conductors	$655,110,476
	% of Conductor Poles and Fittings Associated with Minimum System (P / Q)	33.38%

Say	**Customer**	**33%**
	Demand	**67%**

NOTES:
1- See Schedule 5
2 - See Schedule 2.
3 - Inflated to 2001 using Handy Whitman Index, results provided in Schedule 4.
4 - See Schedule 3
5 - Estimated Split

NEWFOUNDLAND POWER INC.

MINIMUM SYSTEM UNIT COST ESTIMATES

Based on Construction Estimates used for the 2002 CIAC Costing Tables.

Estimated Cost of Minimum Size Pole (35 foot)

Description	Quantity	Labour[1]	Material[1]
35' Pole	1	$385.00	$204.80
Sub Total		385.00	204.80
Total Material & Labour			$589.80
Engineering and Supervision (Labour Only)	25%		96.25
Sub Total			686.05
General Expenses Capitalized	10%		68.61
Total			$754.66

Estimated Cost of Minimum Size Pole Structure

Description	Quantity	Labour[1]	Material[1]
Structure AL	1	38.67	23.58
Sub Total		38.67	23.58
Total Material & Labour			$62.25
Engineering and Supervision (Labour Only)	25%		9.67
Sub Total			71.92
General Expenses Capitalized	10%		7.19
Total			$79.11

NEWFOUNDLAND POWER INC.

ESTIMATED COST OF MINIMUM SIZE CONDUCTOR (URBAN)

Based on 150 ft. Spans of #8 Bare Copper Wire single phase extension.

Description	Quantity	Labour[1]	Material[2]
#8 Bare Copper Wire	per foot	$0.52	$0.14
Sub Total		0.52	0.14
Total Material & Labour		$0.66	
Engineering and Supervision (Labour Only)	25%	0.13	
Sub Total		0.79	
General Expenses Capitalized	10%	0.08	
Total		$0.87	

ESTIMATED COST OF MINIMUM SIZE CONDUCTOR (RURAL)

Based on 250 ft. spans of 1/O AASC Primary

Description	Quantity	Labour[1]	Material[1]
1/0 AASC Primary	per foot	$0.31	$0.186
Sub Total		0.31	0.186
Total Material & Labour		$0.50	
Engineering and Supervision (Labour Only)	25%	0.08	
Sub Total		0.57	
General Expenses Capitalized	10%	0.06	
Total		$0.63	

NOTES:

1 - Material and Labour cost from 2002 CIAC Costing Manual.
2 - Based on a quote for one kilometre of #8 Bare Copper Conductor

NEWFOUNDLAND POWER INC.

ESTIMATED CONDUCTOR MILES

The number of conductor miles is estimated in two components: overhead estimate and underground estimate. The overhead portion is estimated based the number of distribution pole miles. The underground portion is based on the installed feet of cable recorded in plant records.

Estimated number of feet of minimum system conductor required.

Distribution pole miles[1]	4,893	miles
Distribution underground miles[2]	62	miles
Total Number of Feet of Minimum System Conductor		
Overhead (5280 ft/ mile * 2 conductors for single phase)	51,669,062	ft.
Underground (5280 ft/ mile * 2 conductors for single phase)	656,198	ft.
Total	52,325,260	ft.

NOTES:
1 - Latest available estimate based on number of poles times an average span length (2001)
2 - Estimated from drawings and field information in 1992 & 1993. The number has not changed significantly since that time.

NEWFOUNDLAND POWER INC.

ESTIMATED REPLACEMENT VALUE OF CONDUCTORS, POLES AND FITTINGS FOR DISTRIBUTION

The Schedule provides the current dollar estimate of the Plant in Service as determined for insurable property purposes. The portions of Distribution Conductors, Poles and Fittings associated directly with Street Light Plant are removed in the calculations below.

2001 Value of Plant taken from Insurable Property Calculation for December 31, 2001.

Distribution Poles (Includes Service Poles)

Poles and Fixtures - Up to 35 feet	$113,417,063
Poles and Fixtures - Over 35 feet	$345,278,566
Subtotal Replacement Value Distribution Poles and Fixtures	$458,695,629
Wood Poles dedicated to Street Lights - Up to 35 feet[1]	$3,514,332
Wood Poles dedicated to Street Lights - Over 35 feet[1]	$10,698,775
Subtotal Replacement Value Street Lighting	$14,213,107
Estimated Replacement Value of Distribution Plant	**$444,482,522**

Distribution Conductors (Includes Service Wires)

Bare Copper Overhead Conductor	$7,360,974
W/P Copper Overhead Conductor	$14,687,673
Bare Aluminum Overhead Conductor	$137,804,233
W/P Aluminum Overhead Conductor	$35,406,846
Aerial Cable O/H Conductor	$1,580,276
Duplex overhead conductor	$3,907,014
Underground Cables	$24,271,683
Subtotal Replacement Value Distribution Conductors	$225,018,699

Less Street and Area Lighting Conductor

Duplex overhead conductor[2]	$3,907,014
Underground Cables[1]	$10,483,730
Subtotal Replacement Value Street and Area Lighting Conductor	$14,390,744
Estimated Replacement Value of Distribution Conductor	**$210,627,955**

NOTES:
1 - Street Light Portion based on a % of total plant as determined on Schedule 5.
2 - All duplex assumed to be Street Lighting.

NEWFOUNDLAND POWER INC.

ESTIMATED PERCENTAGE OF PLANT ASSOCIATED WITH STREET LIGHTING

Poles under 35' (Includes Service Poles)

	QTY	Cost
Street and Area Lighting wood poles[1]	7,440	$3,720,308
Total wood poles[2]	223,071	$120,064,456
% of costs related to Street and Area Lighting		3.10%

Underground Street and Area Lighting Conductor

Total Cost Underground Conductor[2]	$15,166,986
Total Cost Underground Street and Area Lighting Conductor[2]	$6,551,115
% of costs related to Street and Area Lighting	43.19%
Total number of NTC poles joint use with NP[3]	34,924

Notes:
1. Analysis of Street Lighting Plant Records
2. From 2001 Plant Records
3. As of December 31, 2001

NEWFOUNDLAND POWER INC.

2001 DISTRIBUTION TRANSFORMER ZERO INTERCEPT ANALYSIS

ZERO INTERCEPT ANALYSIS

The zero intercept analysis is based on a regression analysis of the costs of the transformers below 50 kVA. The regression is based on two dependent variables, Quantity and kVA size.

List of the Current Value (2001) of Transformers 50 kVA and Less

	Transformer size KVA	Quantity	Total 2001 Value[2]	Unit Cost	Quantity % of Total
	5	2,095	$863,069	$412	3.74%
	7.5	143	77,487	542	0.26%
	10	8,395	6,621,289	789	14.98%
	15	3,208	2,056,539	641	5.72%
	20	17	14,803	871	0.03%
	25	15,770	16,543,577	1,049	28.13%
	30	6	8,599	1,433	0.01%
	37.5	3,634	3,432,944	945	6.48%
	40	5	7,390	1,478	0.01%
	45	2	4,151	2,075	0.00%
	50	13,162	19,748,014	1,500	23.48%
	75	6,301	12,366,616	1,963	11.24%
	100	1,722	4,236,006	2,460	3.07%
	150	62	192,527	3,105	0.11%
	167	186	673,348	3,620	0.33%
	200	14	67,115	4,794	0.02%
	225	33	208,762	6,326	0.06%
	250	46	235,981	5,130	0.08%
	300	238	2,237,889	9,403	0.42%
	333	3	30,087	10,029	0.01%
	500	249	3,303,811	13,268	0.44%
	600	8	93,602	11,700	0.01%
	750	118	2,102,280	17,816	0.21%
	1000	27	639,488	23,685	0.05%
	1250	1	27,216	27,216	0.00%
	1500	21	620,986	29,571	0.04%
	2500	1	40,266	40,266	0.00%
Padmounts		590	1,702,318		
Mountings & Pads			658,104		
Totals		56,057	78,814,263		

Regression Coeficients:

Unit Size	28.5364		
Quantity	(0.0119)		
Constant	$377.84	(zero intercept)	

Cost of Zero Intercept Transformer	$377.84		
Total Transformer Quantity	56,057		
Total Transformer Plant[2]	$78,814,263		
Customer Component (56,057 * $377.84)	$21,180,839	**27%**	**Customer**
Demand Component ($78,814,263 - $21,180,839)	$57,633,424	**73%**	**Demand**

Notes: 1. From 2001 Plant Records
2. 2001 Value of Plant taken from Insurable Property Calculation for 2001

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OUTPUT of REGRESSION ANALYSIS

Regression Statistics	
Multiple R	0.884618641
R Square	0.78255014
Adjusted R Square	0.728187675
Standard Error	261.9779344
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	1975934.097	987967.0487	14.395045	0.002235818
Residual	8	549059.5049	68632.43811		
Total	10	2524993.602			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Constant	377.8446847	163.0984692	2.316666039	0.0491747
Unit Size	28.53641056	5.318470433	5.365529605	0.0006732
Quantity	-0.01193249	0.014703282	-0.81155284	0.4405242

RESIDUAL OUTPUT

Observation	*Predicted Y*	*Residuals*	*Standard Residuals*
1	495.5281699	-83.56191848	-0.356614252
2	590.1614178	-48.29287358	-0.206097793
3	563.0355326	225.6826822	0.963138021
4	767.6114136	-126.5456511	-0.540054411
5	948.3700436	-77.59955569	-0.331168886
6	903.0795737	145.9741519	0.622968738
7	1233.865407	199.3741723	0.850862122
8	1404.59741	-459.9239035	-1.962801018
9	1519.241445	-41.17731842	-0.175730989
10	1661.959295	413.2990734	1.763821875
11	1647.609773	-147.228859	-0.628323408