Q. (a) Define the following terms:

- Incremental cost
- Short-run marginal cost
- Long-run marginal cost
- Long-run incremental cost

(b) How is each calculated for an integrated electric utility?

(c) How should each of these costs be reflected in rate design?

ANSWER:

a) Mr. Bowman refers to the Glossary of Terms and Abbreviations in the Board's October 10, 1995 Report on *A Referral by the Lieutenant-Governor in Council Concerning Rural Electrical Service* for definitions of short-run and long-run marginal cost, as follows:

Short Run Marginal Cost (SRMC) – The change in total costs when output is increased or decreased by one unit of output for a short period of time (e.g., 1 year), during which system capacity cannot be altered.

Long Run Marginal Cost (LRMC) - The change in total costs when output is increased or decreased by one unit of output for an extended period of time (e.g., 10 years), during which system capacity can be altered.

Mr. Bowman points out that the Glossary does not include definitions for incremental cost and long-run incremental cost. but notes that incremental cost relates to the change in total costs when output is increased by an increment (as opposed to one unit) of output for a period of time (when output is decreased by an increment it is referred to as a decremental cost). Utilities might use incremental costs to approximate marginal costs. In fact, in Hydro's July, 2001 report entitled *An Estimate of Long-run Marginal Costs in Newfoundland and Labrador Hydro's Isolated Rural Areas*. Hydro uses long-run average incremental cost as being representative of LRMC (page 3). Mr. Bowman notes that Hydro uses the definition for LRMC shown above in its July, 2001 report (page 3).

b) Mr. Bowman refers Hydro to the following sources as examples of how marginal costs are calculated by integrated utilities:
   - The 1984 Marginal Cost Study;
   - Newfoundland Light and Power's marginal cost methodology submitted during its 1996 application (attached). It includes calculations of marginal energy costs, marginal transmission and distribution costs and marginal generation demand costs.
   - Hydro's July, 2001 report entitled *An Estimate of Long-run Marginal Costs in Newfoundland and Labrador Hydro's Isolated Rural Areas.*

c) As the Board states in its 1993 Report, "marginal costs should be reflected in rates if efficiency is to be gained'. It is unlikely that pure marginal cost-based rates will recover a revenue requirement based on embedded costs (they may be higher or lower). Therefore, elements of marginal costs must be incorporated in the rate design while recovering the revenue requirement. This can be done in a number of ways. For example, tail-block energy rates can be set to reflect marginal energy costs, and differences in the rates for different time periods can be established on the basis of the marginal cost of supply in the different periods. As for the appropriateness of using long-run versus short-run marginal costs, Mr. Bowman points to a quote in *Principles of Public Utility Rates* by James C. Bonbright, Albert L. Danielson and David R. Kamerschen. "While whether rates should be based upon short-run or long-run marginal costs is a dilemma, we support flexibility in selection depending on the constraints and assumptions." (page 474) The authors go on to say "Marginal cost pricing mandates time of use or peak load rates since marginal costs vary at different times of the day and perhaps of the year." (page 474)

NEWFOUNDLAND LIGHT AND POWER

MARGINAL COSTS

GENERAL DESCRIPTION

Marginal Costs are the change in system costs associated with a very small change in output. For electric utilities units of output are usually defined as either, energy (1 kWh), demand (1 kW) or customer (1 cust). Both marginal energy and demand costs can vary significantly by time of day and season.

A very general description of the marginal cost estimates computed by the Company are given below:

- Marginal Energy Costs are the variable costs associated with supplying a 1 kWh increase in system load with no change in capacity (often called short-run marginal energy costs).
- Marginal Transmission and Distribution (T&D) Costs are the increase in T&D costs associated with supplying a 1kW increase in system load or a new customer (often called long-run marginal T&D costs).
- Marginal Generation Demand Costs are the increase in costs associated with an increase in system load by 1 kW. The costs are based on the annualized capital and fixed operating costs associated with the favoured peaking generation option. For the Island Interconnected system this is a Gas Turbine. The marginal demand costs is weighted by the ratio of expected loss of load days (LOLP) in a given year to the planning target loss of load days per year. This marginal Generation Demand cost is sometimes called short-run generation capacity costs, or value of shortage. This method, developed by the National Energy Research Associates (NERA), recognizes excess capacity in determining marginal demand costs. Long run marginal capacity costs would be the marginal cost of the gas turbine, not adjusted by the ratio of LOLP over target LOLP.

CALCULATION DETAILS

A forecast of marginal costs from 1995 to 2000, without losses included, is shown in Schedule 1. The detailed calculation of marginal energy, marginal T&D, and marginal generation demand costs are discussed below for the base year of 1995. The projection of the marginal costs beyond 1995 are based on a fuel forecast, escalation forecast and LOLE forecast referenced in Schedule 8.

Marginal Energy Costs:

The marginal energy costs are primarily based on the fuel and operating costs associated with the Holyrood Generation Plant. System generation is operated to first maximize the hydraulic generation potential. This hydro production is less than the annual energy and demand requirements of the system. The remaining production requirements are met using thermal production. With the system loads in 1995, almost all the thermal production is met by the Holyrood Generating Plant. The production required from gas turbines and diesels are minimal. Gas turbines and diesels are generally required less than 1% of the time and usually only when other generating plant is out of service due to a forced outage. The lack of need for production from gas turbine and diesels capacity is primarily a reflection of NLH's firm energy criteria.

To calculate marginal energy costs, an estimate of Holyrood fuel and operating costs per kWh is combined with an estimate of gas turbine fuel and operating costs per kWh. For NP's marginal energy costs, we have conservatively weighted Holyrood costs at 95% of total marginal energy and gas turbines at 5%. This weighting is assumed for every year of the forecast period. With NLH's firm criterion, any change in the mix of marginal production over time is expected to be minimal. For 1995, the short run marginal energy cost is estimated on Schedule 2.

Marginal transmission and distribution costs.

To estimate marginal transmission and distribution costs, the general methodology developed for the 1984 Marginal Cost Study was followed. This study has not been revised in detail, but the costs used in the 1984 study were extended to 1995 using many of the factors developed for the 1984 study. These costs were extended by using capital and operating numbers available through year end operating cost reports and budget documents. The marginal costs were calculated for demand and customer components for the following categories of costs:

- NLH Common Assets (Transmission and Terminal Stations)
- NLH Specifically Assigned Assets (Transmission and Terminal Stations)
- NP Transmission
- NP Substations
- NP Distribution (Conductors- Poles-Fixtures, Transformers, Services, Meters)
- NP Customer Related Expenses.

<u>NLH Common Assets & Specifically Assigned Assets</u>

For marginal investment costs, NLH supplied their growth related Transmission and Terminal Station expenditures applicable to the portion of their system grouped as Common, and Specifically Assigned to NP. These costs were provided for the years 1984 to 1993 and were divided by the growth in NLH's System Peak, and NP's System Peak for the common and specifically assigned assets respectively to obtain marginal investment costs. To annualize the investment costs, an economic carrying charge factor was used. The calculation of this factor is shown in schedule 7.

Marginal operating costs was determined as 2% of marginal investment cost.

The calculation of these marginal costs is shown in Schedule 3.

NP's Transmission and Substation Costs

For marginal investment costs, the budget documents from 1984 to 1994 were reviewed to determine the growth related capital investments. These costs were divided by growth in NP's System Peak to obtain marginal investment costs. To annualize the investment costs, an economic carrying charge factor was used. The calculation of this factor is shown in schedule 7.

The operating costs obtained from year end accounting summaries were used to determine marginal operating costs.

The calculation of these marginal costs is shown in Schedule 4.

NP Distribution (Conductors- Poles-Fixtures, Transformers, Services, Meters) and Customer Expenses

For marginal investment costs, the budget documents and year end accounting reports from 1984 to 1994 were used. Using the total capital additions for each group (Conductors- Poles-Fixtures, Transformers, Services, Meters) and classification factors from the 1994 cost of service study and the 1984 marginal cost study, growth related and customer related investments were determined. The classification factors used are shown in Table 1.

The growth related investment costs are divided by growth in NP's System Peak and growth in weighted customers to obtain marginal investment costs. The weighted customer number is determined using the year end number of customers by rate class times a weighting for each rate class. These customer weightings are shown in Table 2. To annualize the investment costs, an economic carrying charge factor was used. The calculation of this factor is shown in schedule 7.

The operating costs obtained from year end accounting summaries were used to determine marginal operating costs.

The calculation of these marginal costs is shown in Schedule 5.

Table 1: Distribution Classification Factors

Cost Category	Classification Factors		
	Demand	Customer	Replacement
Poles, Guys and Fixtures (Total Investment)			
Total Investment	47%	23%	30%
O&M Costs	67%	33%	0%
Transformers			
Total Investment	53%	18%	30%
O&M Costs	75%	25%	0%
Services			
Total Investment	0%	72%	28%
O&M Costs	0%	100%	0%
Meters			
Total Investment	0%	48%	52%
O&M Costs	0%	100%	0%
Customer (Total O&M Costs)	0%	100%	0%

Table 2: Customer Weighting Factors

Rate Class	Weighting Factors				
	Conductors, Poles and Fixtures	Distribution Transformers	Services	Meters	Customer Expenses
Domestic Rate 1.1	1	1	1	1	1
Rate 2.1 1 Phase	1	1	1.2	1.2	1
3 Phase	1	1	3.2	3.2	1
Rate 2.2 1 Phase	1	1	2.5	2.5	2
3 Phase	1	1	3.7	3.7	2
Rate 2.3 Primary	1	0	0	54	3
(100-350) Secondary	1	1	15	15	3
Rate 2.3 Transmission	0	0	0	87	4
(350-1000) Primary	1	0	0	54	4
Secondary	1	1	15	15	4
Rate 2.4 Transmission	0	0	0	90	4
Primary	1	0	0	64	4
Secondary	1	1	21	21	4

Marginal Generation Demand Cost

The Marginal Generation Demand Cost is based on the Peaker Deferral Method. Depending on the use of the marginal cost series, the company uses either;

- the long run marginal demand cost starting in the year a capacity shortage is forecasted
- or, the short run marginal demand cost where over-capacity is recognized by determining the value of shortage.

The long-run marginal generation demand cost is based on the value of deferring peaking capacity by one year, taking into account the reliability of the source upon which the peaking capacity is based (In NP's case, a Gas Turbine is used). The derivation of long-run marginal generation capacity cost is shown in Schedule 6.

The short run marginal generation demand cost is based on the long-run marginal costs, weighted by the ratio of expected loss of load days (LOLP) in a given year to the planning target loss of load days per year. This short-run marginal capacity cost is sometimes referred to as the value of shortage. It is based on recognition of the reliability benefit for additional peaking capability. The derivation of the short-run marginal generation capacity cost is shown in Schedule 6.

NEWFOUNDLAND POWER

Schedule 1

NEWFOUNDLAND LIGHT AND POWER CO. LIMITED
PROJECTION OF SYSTEM MARGINAL COSTS[1]
(Mid-Year Current Dollars)

	MARGINAL DEMAND RELATED COSTS[2]						
		Transmission and Distribution Costs					
Year	Generation Capacity ($/kW-Yr)	NLH TMS Common ($/kW-Yr)	NLH TMS Spec Ass. ($/kW-Yr)	NP TMS ($/kW-Yr)	NP Substation[3] ($/kW-Yr)	NP C, P & F[4] ($/kW-Yr)	NP Dist.Transf. ($/kW-Yr)
1995	16.0	8.8	1.7	3.9	11.4	20.2	6.5
1996	16.9	9.1	1.7	4.0	11.9	21.0	27.8
1997	11.4	9.3	1.8	4.1	12.1	21.4	28.3
1998	8.7	9.3	1.8	4.1	12.1	21.5	28.4
1999	11.7	9.3	1.8	4.1	12.2	21.5	28.5
2000	20.6	9.3	1.8	4.1	12.1	21.3	28.2

	MARGINAL ENERGY RELATED COSTS[5]		
Year	Holyrood Energy (¢/kWh)	C.T. Energy (¢/kWh)	Weighted Total Energy (¢/kWh)
1995	3.7	8.4	3.9
1996	3.7	8.6	4.8
1997	3.9	8.9	4.1
1998	4.0	9.1	4.3
1999	4.1	9.5	4.4
2000	4.3	9.8	4.6

	MARGINAL CUSTOMER RELATED COSTS[6]				
	Distribution and General Costs				
Year	Distribution C, P & F ($/WCUST)	Distribution Transformers ($/WCUST)	Secondaries ($/WCUST)	Meters ($/WCUST)	Customer Related ($/WCUST)
1995	82.0	16.7	50.4	20.2	42.4
1996	85.1	17.4	52.3	21.0	44.0
1997	86.9	17.7	53.4	21.4	44.9
1998	87.0	17.8	53.5	21.5	45.0
1999	87.3	17.8	53.7	21.5	45.1
2000	86.4	17.7	53.2	21.3	44.7

#3.50 / month

1 - The projection in based on a forecast escalation for capital and operating costs, a fuel forecast and LOLP forecast as shown in Schedule 8.
2 - Does not include losses. Unit cost for Generation & NLH Common based on NLH's system peak, unit cost for NLH's specifically assigned, & all NP demand related costs based on NP's system peak.
3 - Includes marginal substation, communications, and system operations/control costs.
4 - C, P & F is an abbreviation for conductors, poles and fixtures.
5 - Does not include losses. Unit cost is based on energy at production level. Losses must be added to determine marginal cost to customer.
6 - Unit costs based on a weighting of the number of customers by rate class and sub-class.

MARGINAL ENERGY COSTS

Estimate for Year 1995

ESTIMATE OF MARGINAL ENERGY COSTS ASSOCIATED WITH HOLYROOD UNITS 1-3.

Fuel Costs

Fuel Forecast (A)	20.4 $/BBL	
Holyrood Efficiency (B)	605 KWh/BBL	
Marginal Fuel Cost (A/B*100)	3.37 cents/kWh	3.37 cents/kWh

Variable O&M

Variable O&M (C)	0.281 cent/kWh (1994$)	
Escalation to current year (D)	1.029 Escalation (94-95)[1]	
Marginal O&M (A*B)	0.29 cents/kWh	0.29 cents/kWh
Total Marginal Energy Costs Associated With Holyrood		**3.66 cents/kWh**

ESTIMATE OF MARGINAL ENERGY COSTS ASSOCIATED WITH GAS TURBINES

Fuel Costs

Fuel Forecast (A)	21.6 cents/l	
Gas Turbine Efficiency (B)	2.988 kWh/l	
Marginal Fuel Cost (A/B)	7.23 cents/kWh	7.23 cents/kWh

Variable O&M

Variable O&M (C)	1.085 cent/kWh (1992$)	
Escalation to current year (D)	1.078 Escalation (92-95)[1]	
Marginal O&M (A*B)	1.169 cents/kWh	1.17 cents/kWh
Total Marginal Energy Costs Associated With Gas Turbines		**8.40 cents/kWh**

WEIGHTED TOTAL MARGINAL ENERGY COSTS FOR THE ISLAND INTERCONNECTED SYSTEM

		Weightings	Weighted Totals
Marginal Holyrood Energy	3.66	95%	3.48 cents/kWh
Marginal Gas Turbine Energy	8.40	5%	0.42 cents/kWh
Total Weighted Marginal Energy Costs			**3.90 cents/kWh**

NOTES:

1 - Based on a GDP Deflator Index supplied by the Conference Board of Canada.

NEWFOUNDLAND POWER

Schedule 3
Page 1 of 2

MARGINAL COSTS FOR NLH's COMMON TRANSMISSION SYSTEM

	Marginal Transmission Investments			Marginal Terminal Station Investments				
Year	Growth Investments Current$[1]	Escalation to 1995[2]	Growth Investments 1995$	Growth Investments Current$[1]	Escalation to 1995[3]	Growth Investments 1995$	NLH System Peak Demand MW[4]	Increase In Peak Load MW
1984	-	1.367	-	-	1.405	-	1,309	63
1985	-	1.354	-	-	1.385	-	1,351	42
1986	-	1.326	-	1,430	1.339	1,915	1,330	(22)
1987	-	1.277	-	1,750	1.246	2,180	1,329	(1)
1988	-	1.170	-	-	1.157	-	1,369	40
1989	-	1.130	-	-	1.073	-	1,419	51
1990	13,867	1.101	15,272	551	1.065	587	1,391	(28)
1991	-	1.126	-	-	1.112	-	1,435	44
1992	-	1.139	-	3,822	1.111	4,247	1,507	73
1993	-	1.110	-	-	1.106	-	1,527	20
TOTALS			15,272			8,929		281

MARGINAL COST OF DEMAND ON NLH's COMMON SYSTEM

Marginal Cost of Capital Additions to Transmission on NLH's Common System

Growth Investments (1995$):	$15,272 (X $1,000)	
Growth	281 MW	
Marginal Investment	54 $/kW	
Annualization Factor	8.18%	
Marginal Demand Cost	4.4 $/kW	4.4 $/kW

Marginal Operating Cost associated with Transmission on NLH's Common System

Marginal Investment (1995$)	54 $/kW	
O&M Percentage	2.00%	
Marginal Demand Cost	1.1 $/kW	1.1 $/kW

Marginal Cost of Capital Additions to Terminal Stations on NLH's Common System

Growth Investments (1995$):	$8,929 (X $1,000)	
Growth	281 MW	
Marginal Investment	32 $/kW	
Annualization Factor	8.23%	
Marginal Demand Cost	2.6 $/kW	2.6 $/kW

Marginal Operating Cost associated with Terminal Stations on NLH's Common System

Marginal Investment (1995$)	32 $/kW	
O&M Percentage	2.00%	
Marginal Demand Cost	0.6 $/kW	0.6 $/kW

TOTAL MARGINAL COSTS ASSOCIATED WITH NLH's COMMON SYSTEM 8.8 $/kW

NOTES:

1 - The capital expenditures related to growth were supplied by NLH.
2 - Escalation index taken from Statistics Canada Utility Construction Price Indicies.
3 - Based on a weighted combination of an NP labour index, and Statistic Canada's Utility Construction price index for Distribution.
4 - Peak for NP's system was normalized based on an average of the load factor for the five years immediately preceding the peak year.

NEWFOUNDLAND POWER

Schedule 3
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MARGINAL COSTS FOR NLH's SYSTEM THAT IS SPECIFICALLY ASIGNED TO NP

Year	Marginal Transmission Investments: Growth Investments Current$[1]	Escalation to 1995$[2]	Growth Investments 1995$	Marginal Terminal Station Investments: Growth Investments Current$[1]	Escalation to 1995$[3]	Growth Investments 1995$	NP System Peak Demand MW[4]	Increase in Peak Load MW
1984	-	1.367	-	-	1.405	-	780	54
1985	-	1.354	-	-	1.385	-	842	62
1986	-	1.326	-	-	1.339	-	874	32
1987	-	1.277	-	-	1.248	-	903	29
1988	-	1.170	-	2,144	1.157	2,481	974	71
1989	-	1.130	-	2,640	1.073	2,832	1,040	66
1990	-	1.101	-	1,049	1.065	1,117	1,100	60
1991	-	1.126	-	-	1.112	-	1,114	14
1992	-	1.139	-	-	1.111	-	1,136	22
1993	-	1.110	-	-	1.106	-	1,119	(17)
TOTALS			-			6,431		393

MARGINAL COST OF DEMAND ON NLH's COMMON SYSTEM

Marginal Cost of Capital Additions to Transmission on NLH's Common System

Growth Investments (1995$):	$0	(X $1,000)	
Growth	393	MW	
Marginal Investment	-	$/kW	
Annualization Factor	8.18%		
Marginal Demand Cost	0.0	$/kW	0.0 $/kW

Marginal Operating Cost associated with Transmission on NLH's Common System

Marginal Investment (1995$)	-	$/kW	
O&M Percentage	2.00%		
Marginal Demand Cost	0.0	$/kW	0.0 $/kW

Marginal Cost of Capital Additions to Terminal Stations on NLH's Common System

Growth Investments (1995$):	$6,431	(X $1,000)	
Growth	393	MW	
Marginal Investment	16	$/kW	
Annualization Factor	8.23%		
Marginal Demand Cost	1.3	$/kW	1.3 $/kW

Marginal Operating Cost associated with Terminal Stations on NLH's Common System

Marginal Investment (1995$)	16	$/kW	
O&M Percentage	2.00%		
Marginal Demand Cost	0.3	$/kW	0.3 $/kW

TOTAL MARGINAL COSTS ASSOCIATED WITH NLH's COMMON SYSTEM 1.7 $/kW

NOTES:
1 - The capital expenditures related to growth were supplied by NLH.
2 - Escalation index taken from Statistics Canada Utility Construction Price Indicies.
3 - Based on a weighted combination of an NP labour index, and Statistic Canada's Utility Construction price index for Distribution.
4 - Peak for NP's system was normalized based on an average of the load factor for the five years immediately preceding the peak year.

NEWFOUNDLAND POWER

MARGINAL COSTS FOR NP's TRANSMISSION SYSTEM

	Marginal Transmission Investments			NP		Transmission Operating Costs			NP	
Year	Total Growth Investments[1] Current$	Escalation[2] to 1995	Total Growth Investments 1995$	System Peak Demand[3] MW	Increase in Peak Load MW	O&M[4] Current $	Escalation[5] to 1995	O&M 1995$	System Peak Demand MW	Marginal Costs $/kW
1985	941	1.354	1,275	842	62	-	-	-	-	-
1986	307	1.326	407	874	32	-	-	-	-	-
1987	44	1.277	56	903	29	-	-	-	-	-
1988	2,236	1.170	2,617	974	71	-	-	-	-	-
1989	831	1.130	939	1,040	66	-	-	-	-	-
1990	1,782	1.101	1,963	1,100	60	955	1.123	1,073	1,100	1.0
1991	794	1.126	894	1,114	14	390	1.074	419	1,114	0.4
1992	994	1.139	1,132	1,136	22	593	1.039	616	1,136	0.5
1993	832	1.110	923	1,119	(17)	500	1.030	515	1,119	0.5
1994	9	1.051	9	1,112	(7)	1,035	1.020	1,055	1,112	0.9
TOTALS			10,216		332					0.7

MARGINAL COST OF NP's TRANSMISSION LINES

Growth Investments (1995$)	$10,216 (X $1,000)		
Growth	332 MW		
Marginal Investment	30.8 $/kW		
Annualization Factor	10.43%		
Marginal Cost of Capital Additions	3.2 $/kW	3.2 $/kW
Marginal Cost of O & M	0.7 $/kW	0.7 $/kW
TOTAL MARGINAL COSTS ASSOCIATED WITH TRANSMISSION		3.9 $/kW

NOTES:

1 - Estimated from capital budget items that were considered growth related.
2 - Escalation index taken from Statistics Canada's Utility Construction Price Indicies.
3 - Peak for NP's system was normalize based on an average load factor for the five years immediately preceding the peak year.
4 - Taken from year end Accounting Reports.
5 - Based on weighed combination of an NP labour index, and Statistics Canada's Utility Construction Price Index for Distribution.

MARGINAL COSTS FOR NP's SUBSTATIONS (Including Communications and Control)

	Marginal Substation Investments			NP		Substation Operating Costs			NP	
Year	Total Growth Investments[1] Current$	Escalation[2] to 1995	Total Growth Investments 1995$	System Peak Demand[3] MW	Increase in Peak Load MW	O&M[4] Current $	Escalation[5] to 1995	O&M 1995$	System Peak Demand MW	Marginal Costs $/kW
1985	715	1.385	990	842	62	-	-	-	-	-
1986	545	1.339	730	874	32	-	-	-	-	-
1987	649	1.246	809	903	29	-	-	-	-	-
1988	3,451	1.157	3,993	974	71	-	-	-	-	-
1989	1,753	1.073	1,881	1,040	66	-	-	-	-	-
1990	6,387	1.065	6,803	1,100	60	4,365	1.123	4,903	1,100	4.5
1991	2,449	1.112	2,723	1,114	14	4,299	1.074	4,617	1,114	4.1
1992	2,975	1.111	3,306	1,136	22	4,803	1.038	4,984	1,136	4.4
1993	618	1.106	683	1,119	(17)	4,727	1.030	4,870	1,119	4.4
1994	57	1.033	59	1,112	(7)	4,584	1.020	4,675	1,112	4.2
TOTALS			21,977		332					4.3

MARGINAL COST OF NP's SUBSTATION PLANT (INCLUDING SYSTEM OPERATIONS AND COMMUNICAITONS)

Growth Investments (1995$)	$21,977	(X $1,000)		
Growth	332	MW		
Marginal Investment	66	$/kW		
Annualization Factor	10.75%			
Marginal Cost of Capital Additions	7.1	$/kW	7.1	$/kW
Marginal Cost of O & M	4.3	$/kW	4.3	$/kW
TOTAL MARGINAL COSTS ASSOCIATED WITH SUBSTATIONS			11.4	$/kW

NOTES:

1 - Estimated from capital budget items for Substation, Communications and Control that were considered growth related. It was dificult to define growth related communications and control, both were considered insignificant and were ignored.
2 - Escalation index taken from Statistics Canada's Utility Construction Price Indicies.
3 - Peak for NP's system was normalize based on an average load factor for the five years immediately preceding the peak year.
4 - Taken from year end Accounting Reports for Substation, Communications and System Operatings.
5 - Based on a weighted combination of an NP labour index, and Statistics Canada's Utility Construction Price Index ...

NEWFOUNDLAND POWER

MARGINAL COSTS ASSOCIATED WITH CONDUCTORS POLES & FIXTURES

Year	Total Distribution C,P & F Invest. Total Investment[1] Current$	Escalation to 1995[2]	Total Investment 1995$	Investment Allocated to Demand Growth[3] 1995$	Investment Allocated to Customer Growth[3] 1995$	NP Normalized Peak Demand[4] MW	Increase in Peak MW	Average Weighted Customers[5] WCUST	Increase in Customers WCUST
1985	8,466	1.345	11,386	5,340	-	842	62	-	
1986	9,023	1.314	11,856	5,561	-	874	32	-	
1987	9,884	1.274	12,597	5,908	-	903	29	-	
1988	10,235	1.201	12,293	5,766	-	974	71	-	
1989	12,588	1.157	14,560	6,829	-	1,040	66	186,317	
1990	13,816	1.121	15,490	7,265	3,578	1,100	60	190,470	4,153
1991	10,082	1.130	11,391	5,342	2,631	1,114	14	194,047	3,578
1992	8,473	1.104	9,356	4,388	2,161	1,136	22	197,509	3,462
1993	7,245	1.077	7,803	3,660	1,803	1,119	(17)	200,794	3,285
1994	8,626	1.042	8,989	4,216	2,076	1,112	(7)	203,980	3,186
TOTALS				54,274	12,250		332		17,663

Year	Total Distribution C,P & F O&M O&M[1] Current$	Escalation to 1995[6]	O&M 1995$	O&M Allocated to Demand Growth[3] 1995$	O&M Allocated to Customer Growth[3] 1995$	Normalized Peak Demand MW	Unit Peak Demand Cost $/MW	Average Weighted Customers WCUST	Unit Peak Customer Cost $/WCUST
1990	4,226	1.123	4,746	3,180	1,566	1,100	2.9	190,470	8.2
1991	4,623	1.074	4,966	3,327	1,639	1,114	3.0	194,047	8.4
1992	4,246	1.038	4,407	2,953	1,454	1,136	2.6	197,509	7.4
1993	3,441	1.030	3,544	2,375	1,170	1,119	2.1	200,794	5.8
1994	4,346	1.020	4,432	2,970	1,463	1,112	2.7	203,980	7.2
Five Year Average							2.7		7.4

MARGINAL COSTS ASSOCIATED WITH NP'S DISTRIBUTION CONDUCTORS, POLES AND FIXTURES (C, P & F).

Marginal Cost Due to Capital Additions	Demand Related		Customer Related	
Growth Investments	54,274	(X $1,000)	12,250	(X $1,000)
Growth	332	MW	17,663	WCUST
Marginal Investment	164	$/kW	694	$/WCUST
Annualization Factor	10.75%		10.75%	
Marginal Demand Cost	17.6	$/kW	74.6	$/WCUST
Marginal Cost Due to Operating Costs				
Marginal Demand Cost	2.7	$/kW	7.4	$/WCUST
TOTAL MARGINAL COSTS FOR C,P & F.	20.2	$/kW	82.0	$/WCUST

Notes:
1 - Taken From Year End Accounting Reports or Budget Documents.
2 - Escalation from Statistics Canada Utility Price Index for Distribution.
3 - Allocated using allocation factors shown in Table 1 of the report.
4 - Peak for NP's system was normalized based on an average load factor for the five years immediately preceding the current peak year.
5 - Weighted Customers Determined using year end customer numbers and weighting factors used in the 1994 cost of service study.
6 - Based on a weighted combination of an NP labour index, and Statistic Canada's Utility Construction price index for Distribution.

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MARGINAL COSTS ASSOCIATED WITH DISTRIBUTION TRANFORMERS (includes Voltage Regulators and Capacitors)

Year	Total Distribution Transformer: Total Investment[1] Current$	Escalation to 1995[2]	Total Investment 1995$	Investment Allocated to Demand Growth[3] 1995$	Investment Allocated to Customer Growth[3] 1995$	NP Normalized Peak Demand[4] MW	Increase in Peak MW	Average Weighted Customers[5] WCUST	Increas In Custom WCUST
1985	1,960	1.345	2,638	1,384	461	842	62	-	
1986	2,527	1.314	3,320	1,743	581	874	32	-	
1987	2,710	1.274	3,454	1,813	604	903	29		
1988	2,810	1.201	3,375	1,772	591	974	71		
1989	3,789	1.157	4,383	2,301	767	1,040	66	186,195	
1990	4,629	1.121	5,190	2,725	908	1,100	60	190,348	4,15
1991	3,216	1.130	3,634	1,908	636	1,114	14	193,928	3,58
1992	1,636	1.104	1,806	948	316	1,136	22	197,387	3,46
1993	1,693	1.077	1,823	957	319	1,119	(17)	200,650	3,26
1994	1,770	1.042	1,844	968	323	1,112	(7)	203,867	3,217
TOTALS				16,520	2,502		332	-	17,672

Year	Total Distribution Transformer: O&M[1] Current$	Escalation to 1995[6]	O&M 1995$	O&M Allocated to Demand Growth[3] 1995$	O&M Allocated to Customer Growth[3] 1995$	Normalized Peak Demand MW	Unit Peak Demand Cost $/MW	Average Weighted Customers WCUST	Unit Peak Customer Cost $/WCUST
1990	1,530	1.123	1,719	1,289	301	1,100	1.2	190,348	1.6
1991	1,324	1.074	1,422	1,067	249	1,114	1.0	193,928	1.3
1992	1,915	1.038	1,987	1,490	348	1,136	1.3	197,387	1.8
1993	1,750	1.030	1,803	1,352	315	1,119	1.2	200,650	1.6
1994	1,600	1.020	1,632	1,224	286	1,112	1.1	203,867	1.4
Five Year Average							1.2		1.5

MARGINAL COSTS ASSOCIATED WITH NP'S DISTRIBUTION TRANSFORMERS

Marginal Cost Due to Capital Additions	Demand Related		Customer Related	
Growth Investments	16,520	(X $1,000)	2,502	(X $1,000)
Growth	332	MW	17,672	WCUST
Marginal Investment	50	$/kW	142	$/WCUST
Annualization Factor	10.75%		10.75%	
Marginal Demand Cost	5.4	$/kW	15.2	$/WCUST
Marginal Cost Due to Operating Costs				
Marginal Demand Cost	1.2	$/kW	1.5	$/WCUST
TOTAL MARGINAL COSTS FOR C,P & F.	6.5	$/kW	16.7	$/WCUST

Notes:
1 - Taken From Year End Accounting Reports or Budget Documents.
2 - Escalation from Statistics Canada Utility Price Index for Distribution.
3 - Allocated using allocation factors shown in Table 1 of the report.
4 - Peak for NP's system was normalized based on an average load factor for the five years immediately preceding the current peak year.
5 - Weighted Customers Determined using year end customer numbers and weighting factors used in the 1994 cost of service study.
6 - Based on a weighted combination of an NP labour index, and Statistic Canada's Utility Construction price index for Distribution.

MARGINAL COSTS ASSOCIATED WITH SERVICES

	Total Investment in Services			Investment			Services Operating Costs				
Year	Total Capital Additions[1] Current$	Escalation to 1995[2]	Total Capital Additions 1995$	Allocated to Customer Growth[3] 1995$	Average Weighted Customers[4] WCUST	Increase in Customers WCUST	O&M[5] Current$	Escalation to 1995[6]	O&M 1995$	Average Weighted Customers WCUST	Unit Customer Cost $/WCUST
1990	2,246	1.121	2,518	1,813	212,220	4,856	1,388	1.123	1,559	212,220	7.3
1991	1,945	1.130	2,198	1,582	216,234	4,014	1,324	1.074	1,422	216,234	6.6
1992	1,623	1.104	1,792	1,290	219,475	3,241	1,444	1.036	1,498	219,475	6.8
1993	1,510	1.077	1,626	1,171	222,375	2,900	1,362	1.030	1,403	222,375	6.3
1994	1,546	1.042	1,611	1,160	225,457	3,082	1,570	1.020	1,601	225,457	7.1
TOTALS				7,016		18,092					6.8

MARGINAL COST OF SERVICES

Growth Investments (1990 - 1994)	7,016	(X $1,000)		
Growth (1990-1994)	18,092	WCUST		
Marginal Investment	388	$/WCUST		
Annualization Factor	11.24%			
Marginal Cost of Capital Additions	43.6	$/WCUST	43.6	$/WCUST
Marginal Cost of O&M (Avg 1990-1994)	6.8	$/WCUST	6.8	$/WCUST
TOTAL MARGINAL COSTS ASSOCIATED WITH SERVICES			50.4	$/WCUST

NOTES:

1 - Taken from Year End Accounting Reports or Budget Documents.
2 - Escalation Index taken from Statistics Canada's Utility Construction Price Indicies.
3 - Determined using allocation factors shown in Table 1 of the report.
4 - Weighted customers determined using year end customer numbers and weighting factors used in the 1994 cost of service study.
5 - Taken from year end Accounting Reports for Services.
6 - Based on a weighted combination of an NP labour index, and Statistics Canada's Utility Construction Price Index for Distribution.

MARGINAL COSTS ASSOCIATED WITH METERS

Year	Total Investment in Meters: Total Capital Additions[1] Current$	Escalation to 1995[2]	Total Capital Additions 1995$	Investment Allocated to Customer Growth[3] 1995$	Average Weighted Customers[4] WCUST	Increase in Customers WCUST	Operating Costs for Meters: O&M[5] Current$	Escalation to 1995[6]	O&M 1995$	Average Weighted Customers WCUST	Unit Customer Cost $/WCUST
1990	1,126	1.121	1,262	606	219,420	4,671	980	1.123	1,101	219,420	5.0
1991	918	1.130	1,037	498	223,374	3,954	1,105	1.074	1,187	223,374	5.3
1992	959	1.104	1,059	508	226,733	3,359	1,216	1.038	1,264	226,733	5.6
1993	759	1.077	817	392	230,768	4,035	1,140	1.030	1,174	230,768	5.1
1994	741	1.042	772	371	232,141	1,373	984	1.020	1,004	232,141	4.3
TOTALS				2,375		17,591					5.1

MARGINAL COST OF METERS

Growth Investments (1990 - 1994)	2,375 (X $1,000)	
Growth (1990-1994)	17,591 WCUST	
Marginal Investment	135 $/WCUST	
Annualization Factor	11.24%	
Marginal Cost of Capital Additions	15.2 $/WCUST	15.2 $/WCUST
Marginal Cost of O&M (Avg 1990-1994)	5.1 $/WCUST	5.1 $/WCUST
TOTAL MARGINAL COSTS ASSOCIATED WITH METERS		20.2 $/WCUST

NOTES:

1 - Taken from Year End Accounting Reports or Budget Documents.
2 - Escalation index taken from Statistics Canada's Utility Construction Price Indicies.
3 - Determined using allocation factors shown in Table 1 of the report.
4 - Weighted customers determined using year end customer numbers and weighting factors used in the 1994 cost of service study.
5 - Taken from year end Accounting Reports for Services.
6 - Based on a weighted combination of an NP labour index, and Statistics Canada's Utility Construction Price Index for Distribution.

NEWFOUNDLAND POWER

MARGINAL COSTS ASSOCIATED WITH CUSTOMER RELATED EXPENSES

Operating Costs for Meters					
Year	O&M[1] Current$	Escalation to 1995[2]	O&M 1995$	Average Weighted Customers[3] WCUST	Unit Customer Cost $/WCUST
1990	7,601	1.123	8,537	200,666	42.5
1991	8,770	1.074	9,420	204,380	46.1
1992	9,037	1.038	9,378	207,859	45.1
1993	8,545	1.030	8,803	211,235	41.7
1994	7,645	1.020	7,796	214,350	36.4
Five Year Average Unit Cost					42.4

TOTAL MARGINAL COST FOR CUSTOMER RELATED EXPENSES: 42.4 $/WCUST

NOTES:
1 - Taken from year end Accounting Reports for Services.
2 - Based on a weighted combination of an NP labour index, and Statistics Canada's Utility Construction Price Index for Distribution.
3 - Weighted customers determined using year end customer numbers and weighting factors used in the 1994 cost of service study.

1995 MARGINAL DEMAND RELATED COSTS ASSOCIATED WITH COMBUSTION TURBINES

ESTIMATED LONG RUN MARGINAL COSTS[1]

- Marginal Investment per kW of System Peak[2] (Includes A & G loading & Overheads)		$952 /kW
- Annualization factor related to capital investment		8.66%
- Annualized Costs		$82.4 /kW
- Capacity Related O&M		
Fixed O&M Costs (1992$)	1.14 $/kW	
Escalation[3]	1.078	
Investment Costs $/kW (1995$)	1.22 $/kW	$1.2 /kW
- Total Capacity Related Marginal Costs		$83.6 /kW
- Total Capacity Costs related to Demand		$83.6 /kW
- Availability Factor		93.70%
TOTAL LONG RUN MARGINAL DEMAND COST FOR GENERATION		$89.2 /kW

ESTIMATED SHORT RUN MARGINAL DEMAND COSTS[4]

- Long Run Marginal Demand Costs:		$89.2 /kW
- Percent Short-run costs are of Long-Run Costs[5]		
LOLE estimate for 1995	0.0358 Days/yr	
Target LOLE	0.2000 Days/yr	
Percentage	17.9%	17.9%
TOTAL SHORT RUN MARGINAL DEMAND COSTS		$16.0 /kW

NOTES:

1 - Applicable for years in which a capacity shortfall is identified.
2 - Based on average of five different estimates. See Schedule 9.
3 - Escalation from Conference Board of Canada Forecasts for GDP Deflator, Jan 1995.
4 - Applicable as value of customer outages (shortage) due to generation unavailability.
5 - LOLE estimate for 1995 peak supplied by NLH, January 12, 1995. See Schedule 8.

Scedule 7

ECONOMIC CARRYING CHARGE CALCULATION

- The following calculation determines the Economic Carrying Charge associated with various types of investments. This calculation is also referred to as the value of deferral.

$$ECC_0{}^1 = \frac{K}{(1 + \text{Discount Rate})} \cdot \frac{(\text{Discount Rate} - \text{Escalation Rate})}{(1 - ((1 + \text{Escalation Rate})/(1 + \text{Discount Rate}))^L)}$$

Where: K = Present Value of Financing Costs Associated with the Investment
L = Life of plant

- Average Escalation Rate (GDP Deflator) = 1.82%

- Discount Rate for determining E.C.C. for NP's assets[2] = 8.47%
- Discount Rate for determining E.C.C. for NLH's assets[2] = 10.18%

- Information of Various Asset Types and the E.C.C. for the initial year of the investment ($E.C.C._0$)

Asset Type	K[3]	Life	$E.C.C._0$	Financing
Gas Turbine	1.034	30	8.66%	NLH Straight Line Depr.
NLH TMS Common	1.047	45	8.18%	NLH Sinking Fund
NLH TMS Specif. Assigned	1.047	45	8.18%	NLH Sinking Fund
NLH Term Station	1.037	40	8.23%	NLH Straight Line Depr.
NLH Hydro	1.048	75	7.98%	NLH Sinking Fund
NP Transmission	1.564	40	10.43%	NP Straight Line Depr.
NP Substation	1.561	35	10.75%	NP Straight Line Depr.
NP Trunk Feeders	1.561	35	10.75%	NP Straight Line Depr.
NP Distribution Transformers	1.561	35	10.75%	NP Straight Line Depr.
NP Services	1.557	30	11.24%	NP Straight Line Depr.
NP Meters	1.557	30	11.24%	NP Straight Line Depr.

NOTES:

1 - Formula Taken from "The NERA Marginal Cost Method for Electric Utilities", A n/e/r/a course Sponsored by the Canadian Electrical Association, North York, Ontario, March 9-11, 1994, Schedule II-2. The NERA Equation is adjusted to represent mid-year cash flows starting in the year plant is installed.

2 - NERA recommends using a utility's after tax cost of capital as the discount rate for determining the economic carrying charge. Since NLH does not pay income tax, NP's after tax discount rate is less than NLH.

3 - The present worth of revenue requirments associated with each plant type, was determined assuming the revenue requirments are discounted to the mid year of the year the plant was installed. The revenue requirement calculation determined financing costs based on an average rate base calculation. The financing costs are as follows:

NLH - 100% Long Term Debt at 8.5%, 8% Interest Coverage & 1% Debt Guarantee Fee
NP - 50% Long Term Debt at 8.5%, 50% Equity at 12.0%, 42% Tax Rate.

Schedule 8

NEWFOUNDLAND POWER

FUEL, ESCALATION INDEX AND LOLE FORECAST

Year	Holyrood Fuel Cost $/BBL	C.T. Fuel Cost ¢/l	GDP Deflator Index (1986=100)	LOLE (Percent)
1995	20.40	21.6	1.338	0.0358
1996	20.80	22.0	1.389	0.0364
1997	21.60	22.9	1.418	0.0242
1998	22.30	23.6	1.421	0.0184
1999	23.20	24.6	1.425	0.0247
2000	24.20	25.6	1.412	0.0438
Average % Escalation 1995 - 2015			1.82%	

1 - Holyrood Fuel Forecast Obtained from Conference Board of Canada February 1996. Forecast does not include any increase in cost due to switching to a lower sulphur fuel.
2 - C.T. Fuel based on Residual (Holyrood) Fuel forecast rebased to 21.6 cents/l for 1995.
3 - GDP Deflator Index Forecast provided by the Conference Board of Canada on December 12, 1995
4 - Supplied by Newfoundland and Labrador Hydro on January 19, 1996.

NEWFOUNDLAND POWER

ESTIMATE OF GAS TURBINE IN-SERVICE COST

Unit	Capacity MW	In-Service Capital Cost $/kW	In-Service Year	Estimate Base Year	Escalation Rate used in estimate	In-Service Cost Base$ $/kW	In-Service Cost In 1995$[1] $/kW
Borden C.T.[2]	45	874	1995	1991	5.00%	719	774
Hydro's GT1[3]	50	1,009	1993	1993	N/A	1,009	1077
Hydro's GT2[3]	50	1,002	1993	1993	N/A	1,002	1069
NLH Goose Bay[4]	26.6	895	1992	1992	N/A	895	964
NP Port Aux Basque[5]	25	821	1993	1993	N/A	821	875
Average In-Service Cost							952

NOTES:
1 - Escalation to 1995 based on Conference Board of Canada GDP deflator index, January 1995.
2 - Estimates From NB, NS and MEC Draft Report on Integrated Resource Planning.
3 - Estimate from Hydro with IDC and escalation during constuction estimated by NP.
4 - From a Demand For Particular during 1992 NLH COS Hearing, NP-6.
5 - A Company estimate which includes + 10% O/H and contingency.