A Study of Innovative Approaches to Rate Design Based on Marginal Costs and Time-of-use Design Principles

June 1997

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EXECUTIVE SUMMARY

The attached report summarizes the investigation and analysis of marginal costs for Newfoundland Power and the design of time-of-use rates based on those marginal costs. The report is not intended to address all of the implementation details and issues surrounding the enclosed rate designs.

Analysis of the load profile for the Island Interconnected System shows that the on-peak season is December through March, and the off-peak season is April through November. The daily peak period during the winter season is quite wide (7:00 A.M. - 10:00 P.M for weekdays, and 9:00 A.M. - 10:00 P.M. for weekends).

The marginal cost for Newfoundland Power's customers is the sum of Newfoundland Power's own marginal costs and the marginal costs of that portion of Hydro's system that is utilized by Newfoundland Power. The resulting marginal costs form the underlying basis upon which the marginal cost based rates described in the report are designed. The marginal energy costs are primarily the costs of the Holyrood generation plant until the requirement for the next generation source. The marginal generation capacity cost in 1997 is assumed to be the cost of deferring a gas turbine for a year. The marginal costs of transmission and distribution are relatively low. We feel that the marginal cost projections are reasonable for the next several years; but due to potential developments on the generation side, the costs beyond the year 2000 should be used cautiously.

A review of Canadian electrical utilities showed that none of the utilities offer residential seasonal rates, and the vast majority do not offer general service seasonal rates. Time-of-day rates are more frequently available for large general service customers than for small general service and residential customers. However, only a small percentage of customers take advantage of time-of-day rates when given the opportunity.

Time-of-use rates (specifically time-of-day and seasonal rates) accomplish the same goals as many of the innovative rates that are offered across North America. Consequently, time-of-day and seasonal rates were designed for each rate class in this report. Other rates such as load retention rates, stand-by rates, and buy-back rates may be worth further investigation if circumstances warrant.

Rates set at the full marginal costs will overcollect the revenue requirement for Newfoundland Power, and therefore must be reconciled back to the embedded revenue requirement. We chose to set the energy price at marginal cost, and reconcile using the demand and customer charges.

Time-of-day rates and/or seasonal rates should only be implemented on a voluntary basis. One of the principal objectives of such rates would be to provide customers with rate options. Making these rates mandatory would not accomplish this objective. Customer impacts are also easier to manage with voluntary rates.

The introduction of voluntary time-of-day or seasonal rates almost always create revenue shortfalls because only customers who can save money go on the rates. Assuming that all customers that will save money on seasonal rates take advantage of these rates, we estimate the revenue shortfall from the implementation of voluntary seasonal rates for Newfoundland Power to be approximately $7 million.

If such rates were to be implemented, some interim mechanism to recover the revenue loss should be implemented until sufficient experience is obtained to accurately estimate the revenue impact and build it into the revenue requirement at a future rate hearing. Limiting entry to the rates will also provide time to evaluate the impact of these rates on overall rates.

Finally, due to the nature of the Company's winter electrical load, the impact of time-of-day and seasonal rates on overall future rates should be considered before a decision to implement these rates on a large scale is made.

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A STUDY OF INNOVATIVE APPROACHES TO RATE DESIGN BASED ON MARGINAL COSTS AND TIME-OF-USE DESIGN PRINCIPLES

1.0 Background and Purpose

In Order No. P.U. 7 (1996-1997) ("the Order"), the Board of Commissioners of Public Utilities of Newfoundland and Labrador ("the Board") considered time-of-day rate design methods and marginal costs. The Board ordered Newfoundland Power to conduct a study of marginal costs and innovative rate designs based on those marginal costs in the following terms:

Marginal cost and time of use design methods should be pursued and will direct the Applicant to pursue innovative approaches based on such methodology.

The Board also agrees with the advice that a study must first be undertaken, and that the study must be well focused and presented to the Board no later than July 1, 1997. The Board expects that the study will include an examination of the utility's load profile as well as its costs.

The Board will not direct the Applicant to any specific innovations (that will be the Applicant's decision) which will be based on its recognized and/or projected problems, its knowledge of existing customer patterns, or its general knowledge of its industry. [Order No. P.U. 7 (1996-1997), pp. 98-99].

"37. A study shall be conducted by July 1, 1997 to evaluate rate designs based upon marginal cost, time-of-day design principles and other innovative rate options...." [Order No. P.U. 7 (1996-1997), p. 107.]

The purpose of this report is to respond to the Board's Order and also to provide a framework for future determinations of marginal costs and rate design decisions by Newfoundland Power. This report is not intended to address all of the many implementation details and issues surrounding the rate designs.

2.0 Approach and Organization of Report

The report follows the same order in which we analyzed marginal costs and time-of-use rate designs. The first task was to perform a load profile analysis to determine what seasonal and on and off-peak time-of-day time periods might be appropriate for Newfoundland Power. The next task was to calculate the marginal costs. Once the marginal costs were calculated, a preliminary review of a wide range of "innovative" rate structures was conducted to determine the types of rates that might be suitable for Newfoundland Power. For the most promising rate types, we then designed and examined specific rate designs in detail. Critical implementation issues, such as revenue reconciliation and rate availability were also examined. The final section summarizes our conclusions and observations.

3.0 Load Profile Analysis

In order to perform marginal cost analysis, and to design time-of-use rates, a load profile analysis is necessary. The load profile analysis identifies periods of the day, week or year when the system is either on or off-peak. Analysis of the load curves, and how the load is served by existing and anticipated new generation, gives insights into the marginal costs of the system and whether there are seasonal and time-of-day differences in the demand on the system. If significant differences do exist, then seasonal and time-of-day rates can be designed.

We have chosen the simple method of defining the peak periods as those hours when load, on average, meets or exceeds 85% of the maximum peak load for the year. The detailed analysis and rationale which led to the selection of these time periods is described in Appendix A.

Based on the analysis, the following time periods were chosen for the marginal cost analysis and time-of-use rate designs:

Seasonal Time Periods

Winter season: December through March (inclusive)

Non-winter season: April through November (inclusive)

Daily Time Periods

Winter weekdays on-peak: 7:00 a.m. - 10:00 p.m.

Winter weekends on-peak: 9:00 a.m. - 10:00 p.m.

Winter weekdays off-peak: 10:00 p.m. - 7:00 a.m.

Winter weekends off-peak: 10:00 p.m. - 9:00 a.m.

Non-winter - April through November (inclusive): all hours off-peak

4.0 Marginal Cost

The calculation of marginal costs for an electric utility is complex. The methods are well described in the NARUC *Electric Utility Cost Allocation Manual* (January, 1992, Section III). In general, we have followed the methods described in the NARUC cost allocation manual, an excerpt of which is attached as Appendix B of this report. The exact methodology and details of the calculation determining the marginal cost of supplying electrical power to the customers of Newfoundland Power is shown in Appendix C.

The calculation was based on the following principles and assumptions:

1. The calculation assumes that the marginal cost of Newfoundland Power's purchased power is Newfoundland and Labrador Hydro's ("Hydro's") marginal cost of supplying Newfoundland Power's load.

2. The calculation of marginal costs excludes all impacts of Voisey Bay Nickel's (VBN) proposed smelter/refinery. It is assumed that VBN will pay all the incremental costs associated with their supply of power. Therefore, the marginal costs to serve existing customers should not be impacted by the VBN load.

3. The marginal cost should reflect the causal relationship between a change in utility cost and a change in either the customer's energy requirements, the customer's peak demand or the total number of customers.

4. The marginal cost should be determined by focusing on future costs as opposed to historic costs. A projection of marginal cost should be incorporated into rate designs so that rate designs can reflect both current and future trends to the extent possible.

The following table summarizes the results of the marginal cost analysis projected to the year 2005.

Table 1
Island Interconnected System
Newfoundland Power's Marginal Costs

	Short Run Marginal Energy Cost		**Long-Run Marginal Demand Cost On-Peak**					**Long-Run Marginal**
Year	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Generation Capacity ($/kW-yr)[1]	Hydro Transmission ($/kW-yr)	Newfoundland Power Transmission ($/kW-yr)	Distribution Primary $/kW-yr)	Distribution Secondary ($/kW-yr)	Customer Cost ($/Weighted Customer)
1997	4.24	4.03	N/A	14.1	1.1	2.4	2.0	330
1998	4.25	4.04	N/A	14.4	1.1	2.4	2.0	336
1999	4.32	4.11	N/A	14.6	1.1	2.5	2.0	342
2000	4.47	4.25	N/A	15.0	1.1	2.5	2.1	350
2001	4.62	4.39	90.2	15.3	3.2	6.5	2.1	358
2002	4.20	3.99	92.5	15.7	3.3	6.7	2.2	366
2003	4.38	4.16	94.8	16.1	3.3	6.9	2.3	375
2004	4.62	4.39	97.2	16.5	3.4	7.0	2.3	384
2005	4.84	4.60	99.8	16.9	3.5	7.2	2.4	394

[1] N/A - Not Available.

The on-peak long-run marginal generation demand-related costs shown in Table 1 have been calculated for the years in which a capacity shortfall is forecasted, which is currently estimated to be in 2001 and beyond. While capacity additions are not required for the years prior to 2001, there is clearly some value to capacity in those years, because there is always a possibility of losing load due to capacity being forced out of service. In the past, Newfoundland Power has used the National Energy Research Associates (NERA) probabilistic methods, which attempt to capture this effect. However, the Loss of Load Probability (LOLP) data used for its application has proven to be unstable. As a result, an estimate of the value of generation capacity for 1997 to 2000 is not available. To develop marginal cost-based rates, we need to assign a generation capacity cost for 1997. We have assumed that the value of generation capacity in 1997 is the full cost of deferring a gas turbine for a year ($83.1 per kW in 1997 dollars).

The 1997 system marginal costs from Table 1 are converted to marginal costs by voltage level and customer type in Table 2. The numbers are different for each customer type because there are different loss factors, and different portions of the system are used by each. There are no off-peak demand costs. The costs from Table 2 are used to design marginal cost based rates.

Table 2
Marginal Cost By Customer Type

Category	Secondary Customer	Primary Customer	Transmission Customer
Energy Cost			
On-Peak (¢/kWh)	4.67	4.55	4.42
Off-Peak (¢/kWh)	4.32	4.24	4.16
Winter (¢/kWh)	4.55	4.45	4.33
Summer (¢/kWh)	4.31	4.23	4.16
Demand Cost			
On-Peak ($/kW-yr)	115.5	110.0	103.2
Customer Cost			
Domestic ($/yr)	330	-	-
Rate 2.1 ($/yr)	364	-	-
Rate 2.2 ($/yr)	636	-	-
Rate 2.3 ($/yr)	2,508	2,611	2,858
Rate 2.4 ($/yr)	7,939	3,007	1,901

5.0 Marginal Cost and Embedded Rates

Most experts agree that to achieve economically efficient pricing it is important to price as close as possible to marginal costs. The extent to which marginal costs are reflected in the embedded rates varies from utility to utility. It is not usually practical to set all rates at marginal cost, so many rate designers try to set at least the run-out rates (or end blocks) as close to marginal costs as seems fair and practical.

5.1 Marginal Cost Compared to Embedded Rates for Newfoundland Power

Tables 3, 4 and 5 compare the marginal costs to the current embedded rates for Newfoundland Power. To make such a comparison meaningful, it is necessary to convert the system costs to rate class costs.

Table 3
Comparison of Existing Basic Customer Charges to 1997 Marginal Costs

	Marginal Customer Cost ($/month)	Embedded Rate(July 1, 1997) Basic Customer Charge ($/month)
Domestic Rate 1.1	27.50	16.56
General Service Rate 2.1	30.32	18.85
General Service Rate 2.2	52.97	20.32
General Service Rate 2.3	209.85	91.45
General Service Rate 2.4	297.61	182.89

Table 4
Comparison of Existing End block Energy Rates to 1997 Marginal Costs

	Marginal Energy Cost (¢/kWh) On-Peak	Marginal Energy Cost (¢/kWh) Off-Peak	Embedded Rate (July 1, 1997) End block Energy Charge (¢/kWh)
Domestic Rate 1.1	4.67	4.32	6.751
General Service Rate 2.1	4.67	4.32	8.828
General Service Rate 2.2	4.67	4.32	4.380
General Service Rate 2.3	4.62	4.29	4.274
General Service Rate 2.4	4.58	4.26	4.178

Table 5
Existing General Service Demand Charges (Embedded Rate July 1, 1997)

	Demand Charge Winter	Demand Charge Summer
General Service Rate 2.2 ($/kW/mth)	7.75	7.00
General Service Rate 2.3 ($/kVA/mth)	6.73	5.98
General Service Rate 2.4 ($/kVA/mth)	6.45	5.70

We can draw several conclusions from Tables 3 to 5:

1. The end block energy rates are set at or above the off-peak marginal cost of energy for all of the existing rates with the exception of Rate 2.3 and Rate 2.4 which are slightly below. The end block energy rates are somewhat below the on-peak marginal cost of energy for Rates 2.2, 2.3 and 2.4.

2. The existing customer charges are substantially below the marginal customer costs.

3. The difference between the existing winter and non-winter demand charges in the embedded rates does not reflect marginal costs. The yearly on-peak demand cost of $103 - $116/ kW from Table 2 would be recovered over the 4 winter months, so the marginal on-peak demand cost is between $26-29/kW/month for the winter months, and $0/kW/month for the non-winter months. The current seasonal difference of $0.75/kVA in the embedded rates is nominal acknowledgment that there is a seasonal difference in demand costs.

6.0 Time-of-Use and Other Innovative Rates in Practice

6.1 Canadian Utility Survey of Innovative Rates

In February 1997, Newfoundland Power did a survey to collect information on the use of marginal costs in rate design, the availability of marginal cost based rates, and the level of customer participation in marginal cost based rates. A questionnaire was sent to 21 Canadian electrical utilities, 17 of whom responded.

The following conclusions were made from the responses provided.

1. Most utilities (88%) do not give marginal costs significant consideration when deriving the endblock energy prices for their standard (non-marginal cost based) rates.

2. None of the respondents offer residential seasonal rates, and the majority (82%) do not offer general service seasonal rates.

3. Time of day ("TOD") rates are more frequently available for large general service customers than for small general service customers and residential customers. Residential TOD rates are available at four, or 24%, of the utilities that responded and TOD rates for general service customers are available at seven, or 41%, of the utilities that responded.

4. A small percentage of customers take advantage of TOD rates when given the opportunity (i.e., less than 0.1% participation rate for residential customers and less than 2% for general service customers).

5. Curtailable rates are offered by the majority of the utilities (82%) that responded, while real-time pricing, stand-by-rates, and surplus energy rates are offered by 59%, 53% and 41% of the utilities respectively.

A more detailed analysis of the survey responses is provided in Appendix D.

The Company has also included as Appendix E the results of a residential TOD survey of U.S. and Canadian utilities conducted in late 1993 by Virginia Power. Ninety-two utilities responded to the survey. Sixty-three, or two-thirds, of the utilities have TOD rates available to residential customers. Of the utilities offering TOD rates, fourteen mandate TOD rates to a segment of their residential customers. The median customers on TOD rates at those utilities with voluntary TOD rates is 120 customers which is equivalent to 0.2% of the total residential class. In other words, one-half of the utilities responding have more than 120 customers on TOD rates, and one-half of the utilities responding have less that 120 customers on TOD rates.

The results of both surveys indicate that voluntary residential time-of-day rates, while available at significantly more utilities in the U.S. than in Canada, generally do not attract significant customer participation. The Canadian survey reveals that none of the responding utilities in Canada offer residential seasonal rates, and the majority do not offer general service seasonal rates.

6.2 Potential Innovative Rates for Newfoundland Power

Newfoundland Power conducted a preliminary review of the innovative rates offered by other electrical utilities. Appendix F summarizes the results of this review.

A properly designed time-of-use rate which reflects marginal costs is superior to the technology specific and other special use rates. Time-of-use rates will accomplish the same goals as these other innovative rates without having to target specific end uses. Specifically, time-of-day rates and seasonal rates offer the greatest potential to the largest number of customers. Time-of-day rates and seasonal rates were designed for each rate class, and are presented in the next section.

Other rates worthy of further consideration include buy-back rates, load retention rates, and stand-by rates. Buy-back rates are rate arrangements whereby the utility pays customers for power supplied by the customer (i.e., a purchased power rate). Standby rates are for the provision of standby power to customers that have their own generation. Load retention rates encourage the deferral of customers' plans to install their own generation where the loss of such loads would result in higher overall rates to customers. These types of rates have not been designed as part of this study but may be desirable in the future if circumstances warrant. The marginal cost study and methodology in this report provides a framework for future determinations of marginal costs and rate designs by Newfoundland Power.

7.0 Time-of-Use Rate Designs for Newfoundland Power

We used the following guidelines in designing time-of-use rates:

1. Rates must be reconciled to the revenue requirement. Rates set at marginal costs will over or under collect the revenue requirement.

2. We cannot set all rate components to the marginal cost so we have decided to set the energy charge at the short-run marginal energy cost.

3. Rates must be designed to promote efficiency. For example, rates must not be designed so that customers can increase their demands for very short periods simply to gain admission to another class and a lower rate.

4. Rates must be practical when compared to the existing embedded rates. Rates should not be designed whereby virtually all customers in a class would have lower bills by moving to a different rate option.

5. The price of a kilowatt or kilowatt-hour for general service customers should only vary on the basis of whether the customer is served at secondary, primary, or transmission voltage. The rate class should not be a factor in determining the price.

7.1 Revenue Reconciliation Methods

If all consumption is priced at marginal costs, the utility will either over or under collect revenues. Rates based on marginal costs must therefore be reconciled to collect the approved revenue requirement. There are several methods mentioned in the NARUC Cost Allocation Manual (Chapter 11) which are commonly used to reconcile marginal cost based rates to embedded revenue requirements. They are:

- Ramsey Pricing (Inverse Elasticity Method)
- Differential Adjustment of Marginal Cost Components
- Equi-proportional Adjustment of Class Marginal Cost Assignments
- Lump Sum Transfer Adjustment

The Ramsey Pricing method uses estimates of elasticity by class and rate component to adjust the marginal cost based rate to yield the proper revenue requirements. Prices for components and rate classes that are the least elastic are adjusted the most. The proper application of Ramsey requires a great deal of elasticity data that is not available.

The Differential Adjustment of Marginal Cost Components makes differential adjustments to the demand, energy and customer components based on judgements about the relative importance of their elasticities of demand. It is a coarser form of Ramsey Pricing.

Equi-proportional Adjustment of Class Marginal Cost Assignments adjusts the marginal cost rates to each class in proportion to the overall amount that marginal cost based rates would over or under collect embedded revenue requirements. It is sometimes viewed as being more fair than the other methods. However, the resulting rates often bear no relation to marginal cost.

The Lump Sum Transfer Adjustment sets all rates to marginal costs and makes up any difference in revenue requirements through a surcharge or rebate on the bill. We did not deem this method practical in Newfoundland.

We have chosen to reconcile rates based on a variation of the Differential Adjustment of Marginal Cost Component method. The method used was to set the energy prices at the short-run marginal cost of energy, and adjust the customer and demand charges according to the guidelines outlined on pages 10 and 11.

Revenue reconciliation from the marginal cost based rates to the embedded cost based rates was performed on the general service classes in total. Revenue reconciliation for each individual rate class was initially attempted, but resulted in differing rate components by rate class that would promote customers to increase usage to reduce cost (by way of moving to a different class with a lower price). We concluded that the most effective pricing structure for general service customers would be achieved through revenue reconciliation of all the general service rate classes (i.e., Rates 2.1, 2.2, 2.3, and 2.4) in total. Because residential customers cannot move between the residential and the general service classes, revenue reconciliation from the marginal cost based rates to the embedded cost based rates was performed separately on the residential class.

The details of the rate design revenue reconciliations are shown in Appendix G.

7.2 Time-of-Use Rates

Two different time-of-use rates were designed: time-of-day rates and seasonal rates.

7.2.1 Time-of-Day Rates

The time-of-day rates are shown in Tables 6 and 7.

Table 6
Energy-Only Time-of-Day Rates

	Domestic	Rate 2.1	Rate 2.2
Basic Customer Charge ($/mth)	$16.16	$25.00	$41.00
On-Peak Energy Charge (¢/kWh)	10.990	16.270	16.270
Off-Peak Energy(¢/kWh)	4.320	4.320	4.320
TOD Metering Surcharge ($/mth)	$2.25	$2.25	$2.25

In the standard rates (i.e., our existing embedded rates), there are no demand charges for the domestic and the general service Rate 2.1 rates. Table 6 shows the domestic and the Rate 2.1 time-of-day rates. The demand costs are recovered in the on-peak energy charge rather than through demand charges.

We also designed an optional energy-only time-of-day rate for general service Rate 2.2 customers. This rate is also shown in Table 6. Some smaller customers have indicated that they do not like paying a demand charge. An energy-only rate will offer these customers the option of not having to pay a demand charge. The on-peak energy charge for the optional energy-only rate is designed to recover the same revenue as the on-peak demand and on-peak energy charges for the Rate 2.2 demand/energy TOD rate. If a customer is billed on this time-of-day energy-only rate, they are paying their demand costs through a higher on-peak energy charge. As long as the customer is paying the on-peak demand cost, it doesn't matter whether the demand cost is recovered through an on-peak demand charge or an on-peak energy charge.

The Rate 2.1 on-peak energy charge was set at the same price as the on-peak energy charge for Rate 2.2 in the optional energy-only rate. This approach provides a smooth transition for customers that move from one class to another. The only difference between the Rate 2.1 and the Rate 2.2 energy-only time-of-day rates is in the higher basic customer charge for Rate 2.2. Both customer charges were set to recover approximately 80% of the marginal customer costs.

Table 7 shows the demand/energy rate for the general service TOD rate. The on-peak and off-peak energy charges were set at the marginal cost of energy when designing the rates. The demand and customer charges were adjusted to reconcile the revenue requirement. A metering surcharge was also included in all of the TOD rates to cover the incremental cost of a TOD meter. We have also included Rate 2.1 on Table 7 for any Rate 2.1 customer who prefers to be billed on a demand/energy time-of-day rate instead of an energy-only rate.

As mentioned earlier, we treated all of the general service rate classes as one rate category for revenue reconciliation purposes. However, the demand and energy charges do vary depending on whether the customer is served at secondary, primary or transmission voltage. The energy charges differ as a result of differences in losses. The demand charges reflect differences in losses, as well as the different components of the system used by secondary, primary and transmission customers. There are also different demand charges for a customer billed on kilovolt-amperes (kVA) than for a customer billed on kilowatts (kW). The demand charges for a customer billed on kilovolt-amperes (kVA) equals 90% of the demand charge for a customer billed on kilowatts (kW). The customer charges differ significantly by customer class to reflect the marginal customer cost differences.

Table 7
General Service Time-of-Day Rates (Demand/Energy)

Basic Customer Charge			
		$/month	
Rate 2.1		$25.00	
Rate 2.2		$41.00	
Rate 2.3		$89.11	
Rate 2.4		$178.22	
TOD Metering Surcharge		$2.25	
Demand Charges			
		$/ kW	$/kVA
Secondary Voltage	On-Peak	$23.52	$21.17
	Off-Peak	$0.00	$0.00
Primary Voltage	On-Peak	$22.39	$20.15
	Off-Peak	$0.00	$0.00
Transmission Voltage	On-Peak	$20.99	$18.89
	Off-Peak	$0.00	$0.00
Energy Charges			
		¢/kWh	
Secondary Voltage	On-Peak	4.670	
	Off-Peak	4.320	
Primary Voltage	On-Peak	4.550	
	Off-Peak	4.240	
Transmission Voltage	On-Peak	4.420	
	Off-Peak	4.160	

Time-of-Day Periods	
Winter weekdays on-peak:	7:00 a.m. - 10:00 p.m.
Winter weekends on-peak:	9:00 a.m. - 10:00 p.m.
Winter weekdays off-peak:	10:00 p.m. - 7:00 a.m.
Winter weekends off-peak:	10:00 p.m. - 9:00 a.m.
Non-winter - April through November (inclusive):	all hours off-peak

7.2.2 Seasonal Rates

The seasonal rates are found in Tables 8 and 9.

Table 8
Energy-Only Seasonal Rates

	Domestic	**Rate 2.1**
Basic Customer Charge($/mth)	$16.16	$25.00
Winter Season Energy Charge (¢/kWh)	8.916	12.164
Non-Winter Season Energy Charge (¢/kWh)	4.310	4.310

The principal difference between the seasonal rates and the TOD rates is that the on-peak period for the seasonal rates is the entire winter period of December through March. There is no demand charge for the off-peak season of April to November. Also, there is no metering surcharge since a TOD meter is not necessary.

The advantage of a seasonal rate over a time-of-day rate is that there is no special metering required. The disadvantage is that the seasonal rate doesn't track marginal costs as well as the time-of-day rate. The seasonal rate treats all of the winter season as on-peak, and doesn't recognize the off-peak period which occurs during the night in the winter.

Table 9
General Service Seasonal (Demand/Energy)

Basic Customer Charge			
		$/month	
Rate 2.1		$25.00	
Rate 2.2		$41.00	
Rate 2.3		$89.11	
Rate 2.4		$178.22	
Demand Charges			
		$/ kW	$/kVA
Secondary Voltage	Winter	$23.58	$21.22
	Non-Winter	$0.00	$0.00
Primary Voltage	Winter	$22.45	$20.20
	Non-Winter	$0.00	$0.00
Transmission Voltage	Winter	$21.04	$18.94
	Non-Winter	$0.00	$0.00
Energy Charges			
		¢/kWh	
Secondary Voltage	Winter	4.550	
	Non-Winter	4.310	
Primary Voltage	Winter	4.450	
	Non-Winter	4.230	
Transmission Voltage	Winter	4.330	
	Non-Winter	4.160	
Seasons			
Winter season:		December through March (inclusive)	
Non-Winter season:		April through November (inclusive)	

7.3 Optional or Mandatory Rates

Whenever innovative rates are designed for existing customers, they may be implemented on either a voluntary or a mandatory basis. There are advantages and disadvantages to each method.

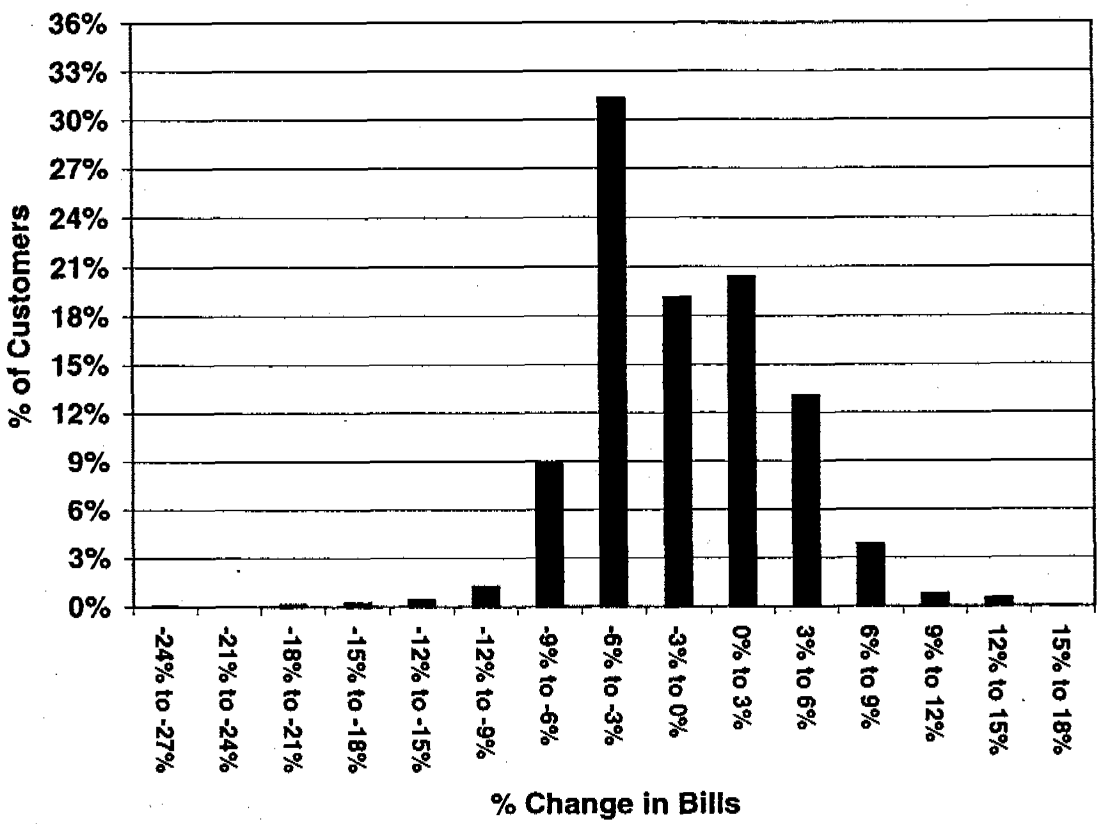
Mandatory rates make it is easier to ensure that everyone is treated equally. They are currently the predominant rate form at Newfoundland Power. The disadvantage of mandatory rates is that they are usually designed to be fair to the average customer, and may not handle special circumstances well. More importantly, they do not give customers choices.

The impact of introducing the seasonal and time-of-day rates on a mandatory basis is revenue neutral to the Company in the short-term. However, the impact on some individual customers is severe. Graph 1 shows the impacts of imposing a mandatory seasonal rate on a sample of approximately 2,100 residential customers. The impact is more severe for a significant number of general service customers. For example, approximately half of Rate 2.4 customers, 15% of Rate 2.2 customers, and 10% of Rate 2.3 customers would receive annual increases greater than 10%. Many of the increases to general service customers are in the range of 30% to 40%.

Voluntary rates give customers choices. They can also be designed so that customers who are unfairly treated by the standard rates are treated more fairly under the voluntary rate. With voluntary rates, only customers who are better off go on the rate, so negative customer impacts are avoided.

Newfoundland Power has designed several new time-of-day and seasonal rates which could be implemented on either a mandatory or a voluntary basis. The fact that both rates are time-differentiated means they both reflect marginal cost better than the existing non-time - differentiated rates. We favor voluntary rates since one of the principal objectives with these rates would be to provide rate options, and making these rates mandatory would not accomplish this objective. Also, customer impacts are easier to manage on a voluntary basis, and customers volunteering to take these rates can bear the cost of special metering.

Graph 1
Impact of Mandatory Seasonal Rates on
Domestic Customers Annual Bills



7.4 Revenue Recovery Mechanisms

The introduction of voluntary time-of-day or seasonal rates almost always creates revenue shortfalls because only customers who can save money will opt for them. The revenue shortfall in the case of seasonal rates is substantial if the take-up rate is high. An estimate of the revenue shortfall for the residential class alone is $3.5 million, if all customers who will benefit from the seasonal rate take advantage of it. Table 10 shows an estimate of the lost revenue by rate class if all customers who benefit from the seasonal rate go on the rate. This analysis is based solely on historical usage patterns. It does not take into account the changes in usage patterns that may occur if such a rate is made available.

Table 10
Revenue Loss From Seasonal Rates

Rate Class	Revenue Loss as a % Class Revenue	Revenue Loss ($000s)
Domestic Rate 1.1	1.7%	3,492
General Service Rate 2.1	5.3%	535
General Service Rate 2.2	3.4%	1,566
General Service Rate 2.3	2.2%	1,121
General Service Rate 2.4	0.5%	86
Total		6,800

There are several ways of dealing with such a revenue shortfall. First, a utility can simply try to estimate who will opt for the new rate and how much revenue they will contribute. Total revenue requirements from the remainder of the class can then be increased to avoid any shortfall in revenue. This method can only be used as part of a rate application. The problem with this method is that it is difficult to estimate the behavior of customers on a time-of-use rate that is dramatically different than existing rates. Also, it is impossible to forecast the revenue shortfall from time-of-day rates without time-of-day meters on a large sample of customers. Any estimates of revenue shortfall may be incorrect by a wide margin. The risks of this method can be reduced by limiting entry on the new rates to a maximum number of customers between rate hearings. This provides time for both the utility and the customer to gain experience with the rates.

Another method for dealing with the revenue shortfall from voluntary rates is to institute a revenue recovery clause. This clause would operate as a rider on the rates and would be applied on a yearly basis by comparing the revenues from customers on the new rates to what they would have contributed under the old rates, and applying the shortfall to the other customers in the class.

7.5 Implementation Issues

7.5.1 Additional Cost of Time-of-Day Rates

Newfoundland Power's Customer Service System (CSS) will need to be modified to enable billing of customers on time-of-day rates. The two major changes required are:

i) an upgrade to the handheld meter reading system, and

ii) the billing module programming changes.

The cost of the upgrade to the handheld system will be approximately $100,000, and the cost of the required programming changes will be approximately $200,000.

Newfoundland Power will have to purchase TOD meters for all participants. We propose to recover the incremental cost of purchasing TOD meters (compared to non-TOD meters) through a surcharge on participants' monthly customer charge. The TOD surcharge would be $2.25/month for all rate classes. For purposes of presentation on the customers' bills, this TOD surcharge could be included in the customer charge on the bill.

7.5.2 Impact on Customers' Rates

There are mechanisms to deal with revenue recovery. However, the implementation of time-of-day and/or seasonal rates can have implications for overall rates. For example, time-of-use rates can have an impact on end uses such as electric heat because time-of-use prices are higher in the winter period. This, in turn, could impact overall sales levels which would have a tendency to increase rates. Before the implementation of the rates discussed in this report to customers on a large scale, the impact on overall rates must be considered. Initially limiting entry on any rates that are implemented can serve both to limit impacts and provide an experience base to more reliably evaluate the future impact on overall rates.

8.0 Conclusions

After reviewing the marginal costs and potential rate designs available for Newfoundland Power between 1997 and 2005, we have reached the following conclusions:

1. The marginal costs of transmission and distribution are relatively low for most areas of the system for many years into the future.

2. The marginal energy costs of generation are primarily those of Holyrood until the requirement for the next generation source.

3. The on-peak marginal costs for Newfoundland Power are higher than the existing embedded end block rates; and the off-peak marginal costs are lower than the existing end block rates.

4. Time-of-use rates (specifically, optional time-of-day rates and seasonal rates) are superior to the technology specific and other special use rates. The implementation of time-of-use rates accomplishes the same goals as these other rates. Therefore, we have designed optional time-of-day and seasonal rates for each rate class. However, other rates such as buy-back rates, stand-by rates, and load retention rates may be worth further investigation if the circumstances warrant.

5. The preferred method of revenue reconciliation at this time is a variation of the Differential Adjustment of Marginal Cost Components. The revenue reconciliation from marginal cost revenue to embedded cost revenue must be done in total for the general service classes in order to develop rates that reflect marginal costs and promote efficiency.

6. If innovative marginal cost based rates are to be implemented, they should be done on a voluntary basis. The implementation of marginal cost based rates on a voluntary basis will create customer choices while improving the economic efficiency of the system. Offering

voluntary time-of-day and/or seasonal rates will result in substantial revenue shortfalls (particularly in the case of seasonal rates).

7. Some mechanism to recover the revenue losses should be provided until sufficient experience is obtained to accurately estimate the revenue impact, and build this impact into the revenue requirement at a future rate hearing. Limiting entry to the rates will also provide time to evaluate the impact of these rates.

8. The introduction of time-of-day and/or seasonal rates may impact the level of overall rates. Before the implementation of these rates to customers on a large scale, the impact on overall rates should be considered.

A STUDY OF INNOVATIVE APPROACHES TO RATE DESIGN BASED ON MARGINAL COSTS AND TIME-OF-USE DESIGN PRINCIPLES

APPENDICES

NEWFOUNDLAND
POWER
A FORTIS COMPANY

APPENDIX A

LOAD PROFILE ANALYSIS

LOAD PROFILE ANALYSIS

1.0 Introduction

The load profile analysis is necessary to perform marginal cost analysis, and to design time-of-use rates. The load profile analysis identifies periods of the day, week or year when the system is either on or off-peak. Analysis of the load curves and how the load is served by current and anticipated new generation gives insights into the marginal costs of the system and whether there are appropriate seasonal and time-of-day differences on the system. If significant differences do exist, then seasonal and time-of-day rates can be designed.

There are a number of ways used to determine appropriate on-peak and off-peak time periods. The simplest method is to choose hours where the load is expected to exceed a certain fraction of the peak, say 85% for example. Another method is to choose hours where the marginal costs are expected to rise appreciably; whenever intermediate generating units might be expected to run, for example. Some analysts prefer to establish time periods by looking at probabilities that load might be lost in any given hour and designating peak periods as those hours which have loss of load probabilities that are close to the peak hour. All of these methods require judgment. The probability methods require sophisticated computer modeling of the generation system, which is not available to Newfoundland Power at this time.

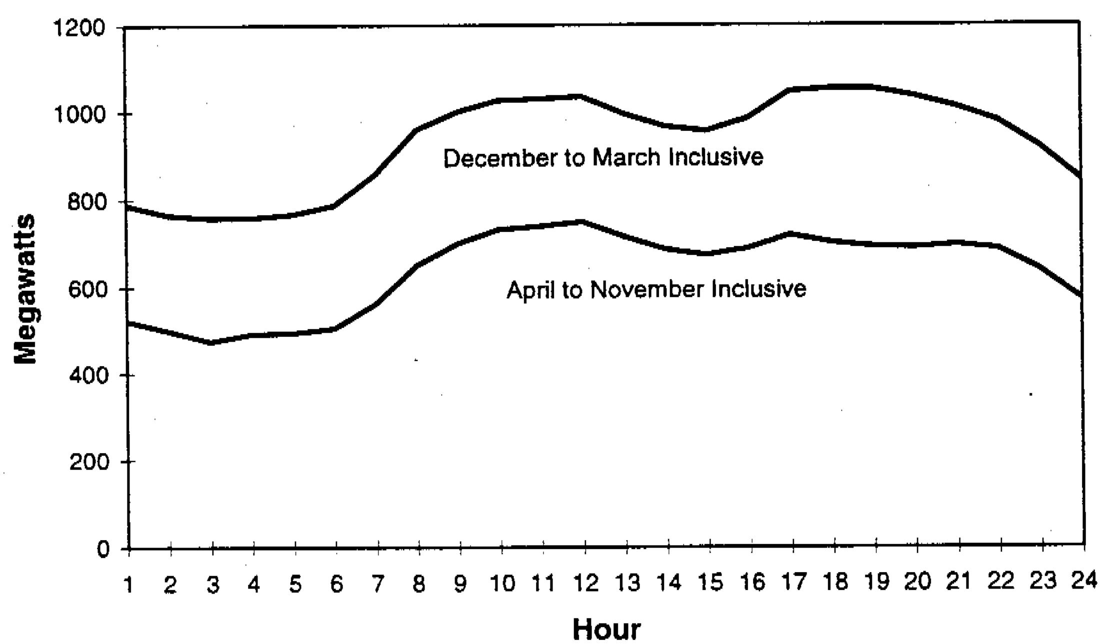
If rate design is the final object, as it is here, selection of time periods should consider whether rate designs based on the selected time periods are practical to administer and easy for customers to remember and understand. Since Holyrood is the marginal unit for almost every hour of the year, there is currently little difference in short-run marginal energy costs between on-peak and off-peak hours. This rules out using appreciable time differences in energy costs as a method for time period selection. The primary difference in costs between on-peak and off-peak are the demand related fixed costs. These are usually associated with on-peak periods, but there is no clear demarcation as to when they begin and end. We have therefore chosen the simple method of defining the peak periods as those hours when load meets or exceeds 85% of the maximum peak load for the year.

We analyzed the load profiles for the Island Interconnected System for the years 1992-1996 by month to determine what seasonal patterns exist.

2.0 Seasonal Peak Periods

Graph 1 shows the typical daily load curve for December through March and April through November periods. As can be seen from Graph 1, the peak season defined as December through March has significantly higher loads than the April through November off-peak season. The average demands during the hours of lowest usage during the on-peak season are higher than average demands during the hours of highest usage during the off-peak season. We have therefore defined December through March as the on-peak season. This definition of seasonal peak period is also convenient as it is consistent with the current definition of winter season used in the standard demand/energy rates.

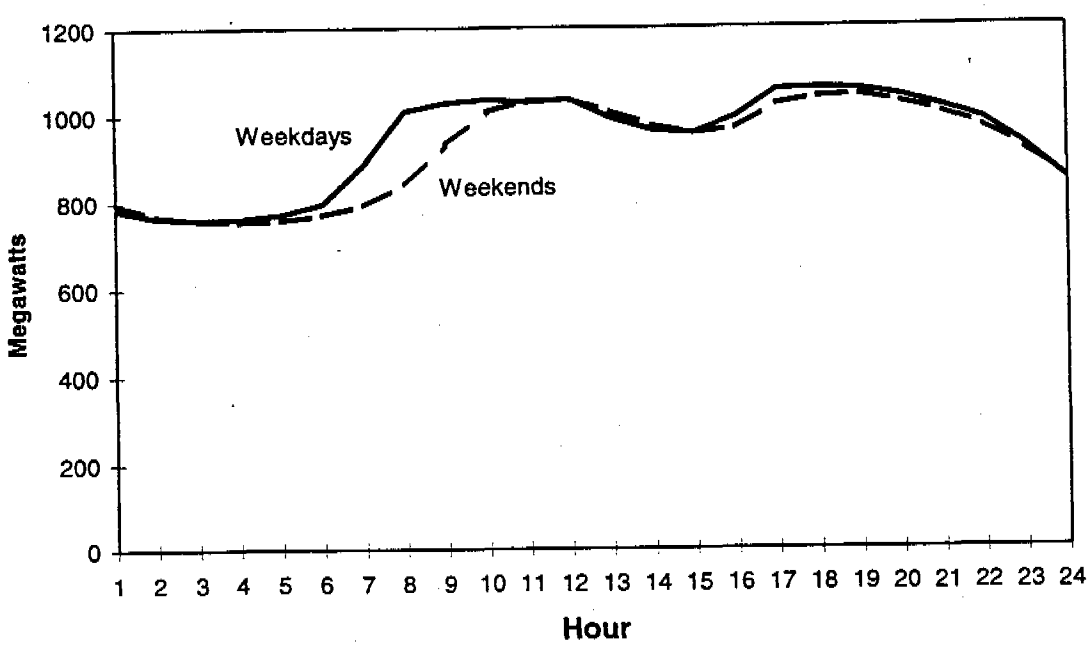
Graph 1- Average Hourly Demands 1992-1996



3.0 Peak Season Weekend versus Weekday Usage

Graph 2 compares the average on-peak season demands for weekend (i.e., Saturday and Sunday) to weekday usage. The data indicates slightly higher loads during the evening hours for the weekdays; but the differences are not significant enough to justify treating the weekend loads any different than the weekday loads, except to consider delaying the start of the peak period a few hours on weekends.

Graph 2 - Average Winter Loads - Weekends vs Weekdays

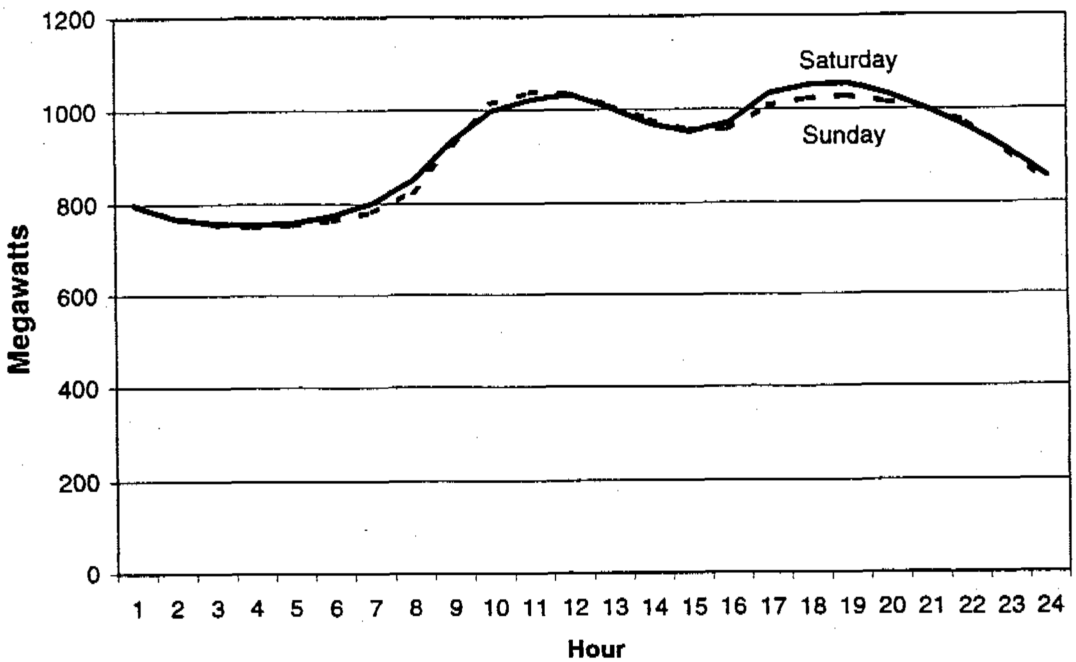


4.0 Saturday versus Sunday Usage

An additional analysis was performed to compare Saturday usage to Sunday usage during the peak season (see Graph 3). This was done to determine if either day could be treated as off-peak or shoulder-peak. The results indicated that Sunday has a slightly higher peak on average during the morning to noon hours, whereas Saturday has a slightly higher peak during the evening hours.

There is not a sufficient difference in the customers' peak season load requirements on Saturdays versus Sundays to justify treating these days differently.

Graph 3 - Saturday vs Sunday Hourly Loads during the Winter Period

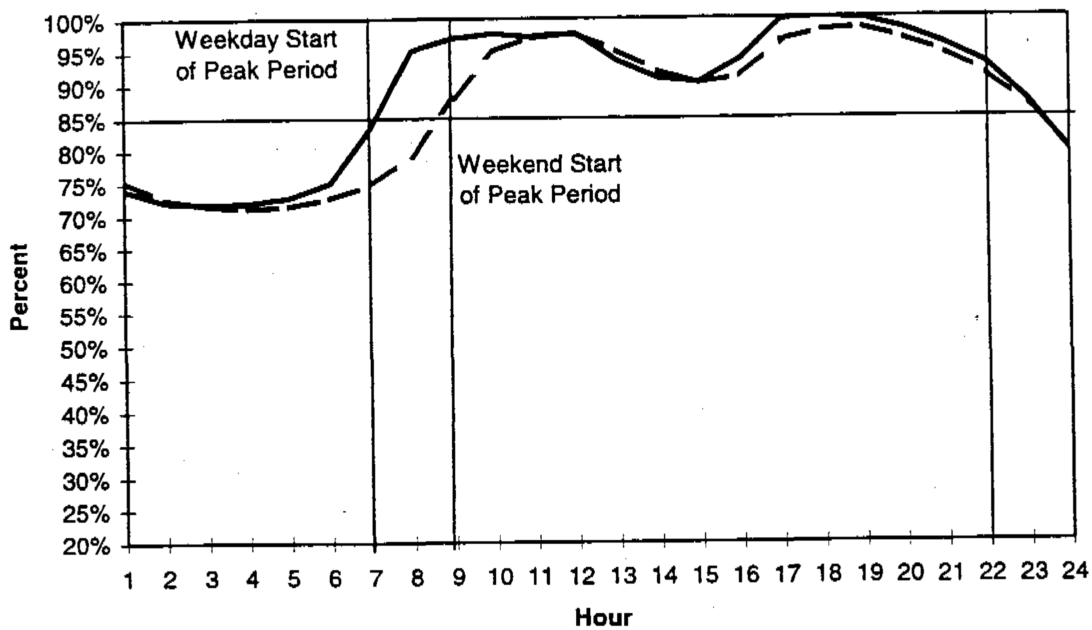


5.0 Winter Season On-Peak and Off-Peak Hours

Graph 4 shows the winter period weekday and weekend time-of-day usage pattern that was shown on Graph 2. Because the weekday usage at 8 a.m. is on average 95% of peak load and the system occasionally peaks at 8 a.m., it is necessary to start the peak period before 8 a.m. At 7 a.m. the load is on average 85% of peak. The customers' usage ramps up very quickly between 7 a.m. and 8 a.m. It is therefore recommended the weekday peak period start at 7 a.m.

The winter weekday load generally does not drop below 85% of peak again until after 11 p.m. However, because of the sharp decline in usage between 10 p.m. and 11 p.m., there is very little risk that the system will peak after 10 p.m. It is recommended that the weekday peak period end at 10 p.m. The usage on winter weekends climbs rapidly towards the morning peak about 2 hours later than during the weekdays. For this reason, and to give the customers a chance to shift more load during the weekends, we have delayed the winter weekend peak period until 9 AM.

Graph 4 - Hourly Loads as a % of Peak Hourly Loads



The decline of usage during the evening on weekends follows the same pattern as on weekdays. It is therefore recommended that the winter peak period end at the same time for both weekdays and weekends.

6.0 General Discussion of Costs of Serving the Load Curve

Although we have chosen the simple method of choosing time periods when load exceeds 85% of peak for defining on-peak and off-peak time periods, the real purpose of choosing time periods is to try to distinguish between times when costs are significantly higher than other times. The marginal costs of providing service in the selected time periods are discussed in detail in Appendix C. Marginal costs can be broken down into marginal demand, marginal energy and marginal customer related costs.

As previously stated there is very little hourly difference in the marginal energy costs between on-peak and off-peak, because the Holyrood units supply the marginal energy during almost all hours of the year. Occasionally combustion turbines are run when there is a unit failure at Holyrood; but this happens for less than 1% of the hours in a year. As load continues to grow, there is more chance that higher operating cost combustion turbines will be used.

Marginal demand costs are incurred because of the highest demands on the system. We have therefore assigned all marginal demand-related costs to the on-peak periods.

Marginal customer-related costs occur whenever a new customer is added. They primarily cover the fixed costs associated with the meters up to the portion of the distribution system that must be constructed anyway when a customer connects. Marginal customer costs apply to all time periods.

7.0 Summary of Recommended Time Periods

The following time periods were chosen for the marginal cost analysis and time-of-use rate designs.

Seasonal Time Periods

Winter season: December through March (inclusive)

Non-winter season: April through November (inclusive)

Daily Time Periods

Winter weekdays on-peak: 7:00 a.m. - 10:00 p.m.

Winter weekends on-peak: 9:00 a.m. - 10:00 p.m.

Winter weekdays off-peak: 10:00 p.m. - 7:00 a.m.

Winter weekends off-peak: 10:00 p.m. - 9:00 a.m.

Non-winter - April through November (inclusive): all hours off-peak

APPENDIX B

EXCERPT FROM 1992 NARUC COST ALLOCATION MANUAL ON MARGINAL COSTS

ELECTRIC UTILITY
COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS
1102 Interstate Commerce Commission Building
Constitution Avenue and Twelfth Street, NW
Post Office Box 684
Washington, DC 20044-0684
Telephone No. (202) 898-2200
Facsimile No. (202) 898-2213

Price: $25.00

SECTION III

MARGINAL COST STUDIES

SECTION III reviews marginal cost of service studies. As noted in Chapter 2, in contrast to embedded studies where the issues primarily involve the allocation of costs taken from the company's books, the practical and theoretical debates in marginal cost studies center around the development of the costs themselves.

Chapter 9 discusses marginal production costs, including the costing methodologies and allocation to time periods and customer classes of the energy and capacity components.

Chapter 10 discusses the costing methodologies and allocation issues for marginal transmission, distribution and customer charges.

Use of marginal cost methodologies in ratemaking is based on arguments of economic efficiency. Pricing a utility's output at marginal cost, however, will only by rare coincidence recover the allowed revenue requirement.

Chapter 11 discusses the major approaches used to reconcile the marginal cost results to the revenue requirement.

CHAPTER 9

MARGINAL PRODUCTION COST

Marginal production cost is the change in the cost of producing electricity in response to a small change in customer usage. Marginal production cost includes an energy production component, referred to as marginal energy cost, and a generation-related reliability component, referred to as marginal capacity cost. Marginal capacity cost is one reliability-related component of the marginal costs associated with a change in customer usage. The other components, marginal transmission cost and marginal distribution cost, are discussed in Chapter 10. Together, these three reliability-related marginal costs are sometimes referred to as marginal demand cost. These marginal costs are used to calculate marginal cost revenues, which are used in cost allocation, as discussed in Chapter 11.

Marginal costs are commonly time-differentiated to reflect variations in the cost of serving additional customer usage during the course of a day or across seasons. Marginal production costs tend to be highest during peak load periods when generating units with the highest operating costs are on line and when the potential for generation-related load curtailments or interruptions is greatest. A costing period is a unit of time in which costs are separately identified and causally attributed to different classes of customers. Costing periods are often disaggregated hourly in marginal cost studies, particularly for determining marginal capacity costs which are usually strongly related to hourly system load levels. A rating period is a unit of time over which costs are averaged for the purpose of setting rates or prices. Rating periods are selected to group together periods with similar costs, while giving consideration to the administrative cost of time-differentiated rate structures. Where time-differentiated rates are employed, typical rate structures might be an on-peak and off-peak period, differentiated between a summer and winter season.

Two separate measures of marginal cost, long-run marginal cost and short-run marginal cost, can be employed in cost allocation studies. In economic terms, long-run marginal cost refers to the cost of serving a change in customer usage when all factors of production (i.e., capital facilities, fuel stock, personnel, etc.) can be varied to achieve least-cost production. Short-run marginal cost refers to the cost of serving a change in customer usage when some factors of production, usually capital facilities, are fixed. For example, if load rises unexpectedly, short-run marginal cost could be high as the utility seeks to meet this load with existing resources (i.e., the short-run perspective). Similarly, if a utility has surplus capacity, short-run marginal cost could be low, since capacity additions would provide relatively few benefits to the utility. When a utility system is optimally designed (utility facilities meet customer needs at lowest total cost), long-run and short-run marginal costs are equal.

A common source of confusion in marginal cost studies arises in considering the economic time frame of investment decisions. There is an incorrect tendency to equate long-run marginal cost with the economic life of new facilities, suggesting that long-run marginal cost has a multi-year character. In actuality, both short-run and long-run marginal costs are measured at a single point in time, such as a rate proceeding test year.[1]

There is considerable difference of opinion as to whether short-run or long-run marginal cost is appropriate for use in cost allocation. In competitive markets, prices tend to reflect short-run marginal costs, suggesting that this may be the appropriate basis for cost allocation. However, long-run marginal costs tend to be more stable and may send better price signals to customers making capital investment decisions than do short-run marginal costs.[2]

I. MARGINAL ENERGY COSTS

Marginal energy cost refers to the change in costs of operating and maintaining the utility generating system in response to a change in customer usage. Marginal energy costs consist of incremental fuel or purchased power costs[3] and variable operation and maintenance expenses incurred to meet the change in customer usage. Fixed fuel costs associated with committing generating units to operation are also a component of marginal energy costs when a change in customer usage results in a change in unit commitment.[4]

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[1]In contrast, analysis of investment decisions properly requires a projection of short-run marginal cost over the economic life of the investment. Long-run marginal cost is sometimes used to estimate projected short-run marginal cost (ignoring factors such as productivity change which may cause long-run marginal cost to vary over time), which perhaps contributes to the mistaken views regarding the economic time frame of long-run marginal cost.

[2]See, for example, the discussion in A. E. Kahn, The Economics of Regulation: Principles and Institutions, 1970, particularly Volume 1, Chapter 3.

[3]Incremental fuel costs are sometimes referred to as system lambda costs.

[4]These fixed fuel costs are commonly associated with conventional fossil fuel units which are used to follow load variations. These units often require a lengthy start-up period where a fuel input is required to bring the units to operational status. The cost of this fuel input is referred to as start-up fuel expenses. Also, at low levels of generation output, average fuel costs exceed incremental fuel costs because there are certain "overhead" costs, such as frictional losses and thermal losses, which occur irrespective of the level of the level of generator output. These costs are sometimes referred to as "no-load" fuel costs since they are unrelated to the amount of load placed on the generating unit.

A. Costing Methodologies

The predominant methodology for developing marginal energy costs is the use of a production costing model to simulate the effect of a change in customer usage on the utility system production costs. Typically, a utility will operate its lower production cost resources whenever possible, relying on units with the highest energy production costs only when production potential from lower-cost resources has been fully utilized. Thus, the energy production costs for the most expensive generating units on line are indicative of marginal energy costs. However, utility generating systems are frequently complex, with physical operating constraints, contractual obligations, and spinning reserve requirements, sometimes making it difficult in practice to easily determine how costs change in response to a change in usage. A detailed simulation model reflecting the important characteristics of a utility's generating system can be a very useful tool for making a reasonable determination of marginal energy costs.

An alternative to using a production costing model is to develop an estimate of marginal energy costs for an historical period and apply this historical result to a test year forecast period. For historical studies, marginal energy costs can be expressed in terms of an equivalent incremental energy rate (in BTU/KWH), which reflects aggregate system fuel use efficiency. Expressing marginal energy costs in these units nets out the effect of changing fuel prices on marginal energy costs [5]. The use of historical studies should be approached with caution, however, when there is a significant change in system configuration (e.g., addition of a large baseload generating station), or where there are sizable variations in hydro availability. In these instances, system efficiency may change sufficiently to render historical studies unreliable as the basis for a test year forecast.

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[5] The incremental energy rate, or IER, is conceptually similar to an incremental heat rate, but measures aggregate system efficiency rather than unit-specific efficiency. The IER is calculated by dividing marginal energy costs by the price of the fuel predominantely used in meeting a change in usage. When the price of this predominant fuel changes, marginal energy cost can be approximated as the fuel price (¢/BTU) times the IER (BTU/KWH).

1. Production Cost Modeling

There are numerous computer models suitable for performing a simulated utility dispatch and determining marginal energy costs that are commercially available[6]. These production cost models require a considerable degree of technical sophistication on the part of the user. In general, results are highly sensitive both to the structural description of the utility system contained in the input data and the actual values of the input data. Verification or "benchmarking" of model performance in measuring marginal energy costs is an important step which should be undertaken prior to relying on a model in regulatory proceedings.

Typically, production cost models produce an output report showing marginal energy costs by hour and month. These reported costs represent the incremental cost of changing the level of output from the most expensive generating unit on line to meet a small change in customer usage. However, these costs do not include the effect of temporal interdependencies which should be accounted for in marginal energy costs. For example, if a unit with a lengthy start-up cycle is started on Sunday evening to be available for a Monday afternoon peak, the costs of starting up the unit are properly ascribed to this Monday peak period.

The effect of such temporal interdependencies can be measured with a production cost model using the incremental-decremental load method. The production cost model is first run to establish a base case total production cost. Then, for each costing period, two additional model runs are performed, adjusting the input load profile upward and downward by a chosen amount. The change in total production cost per KWH change in load is calculated for both the incremental and decremental cases, and the results averaged to give marginal energy costs by costing period.

The results of a production cost model simulation for the utility case study are shown in Table 9-1. The analysis uses an incremental/decremental load method to account for fixed fuel expenses associated with the additional unit commitment needed to meet a change in load during on-peak and mid-peak periods. Off-peak marginal energy costs are derived directly from the production cost model's reported marginal energy costs, since changes in off-peak usage are not anticipated to affect unit commitment. and

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[6]Comparing and contrasting the efficacy of different production costing models is a complex undertaking that will not be attempted in this manual. The "state-of-the-art" in production cost modeling is envolving rapidly, with existing models increasing in sophistication and new models being developed.

mid-peak periods. Off-peak marginal energy costs are derived directly from the production cost model's reported marginal energy costs, since changes in off-peak usage are not anticipated to affect unit commitment.

TABLE 9-1

MARGINAL ENERGY COST CALCULATION USING AN INCREMENTAL/DECREMENTAL LOAD METHODOLOGY

(Based on a Gas Price of $2.70/MMBTU)

	500 MW Decrement	500 MW Increment	Combined
Summer On-Peak			
Change in Production Cost ($)	-9,120	+9,209	18,329
Change in KWH Production (GWH)	-261	+261	522
Marginal Cost (¢/KWH)			3.5
In BTU/KWH			12,993
Summer Mid -Peak			
Change in Production Cost ($)	-9,613	+9,631	19,244
Change in KWH Production (GWH)	-393	+393	786
Marginal Cost (¢/KWH)			2.4
In BTU/KWH			9,089
Summer Off-Peak			
Marginal Cost (¢/KWH)	-	-	2.2
In BTU/KWH			8,129
Winter On-Peak			
Change in Production Cost ($)	-9,930	+11,479	21,409
Change in KWH Production (GWH)	-348	+348	696
Marginal Cost (¢/KWH)			3.1
In BTU/KWH			11,393
Winter Mid-Peak			
Change in Production Cost ($)	-19,843	+19,411	39,254
Change in KWH Production (GWH)	-785	+785	1,576
Marginal Cost (/KWH)			2.5
In BTU/KWH			9,260
Winter Off-Peak			
Marginal Cost (¢/KWH)	-	-	2.4
In BTU/KWH			8,730

Note: These figures exclude variable operation and maintenance expenses of 0.3¢/KWH.

2. Historical Marginal Energy Costs

Where production cost model results are not available, use of historical data as a proxy to forecast future marginal energy costs may be considered. The starting point to estimating historical marginal energy costs is incremental fuel cost (system lambda) data. A number of adjustments to these system lambda costs may be necessary in order to properly calculate marginal energy costs. In low-load periods, production from baseload units or power purchases may be reduced below maximum output levels, while higher cost units are left in operation to respond to minute-to-minute changes in demand. In this instance, the cost of power from the baseload units or purchases with reduced output, not system lambda, represents marginal energy costs. Similarly, in a high-load period, the cost of power from on-line block-loaded peaking units would represent marginal energy cost, even though the cost of these units may not be reflected in the system lambda costs. In a system dominated by peaking hydro, but energy constrained, the cost of production from non-hydro units which serve to "fill the reservoir" represents marginal energy costs.

Another necessary adjustment would be to account for the fixed fuel costs associated with a change in unit commitment when there is a change in load. This fixed fuel cost can be estimated as follows. First, identify how an anticipated change in load affects production scheduling. For example, if production scheduling follows a weekly schedule, an increase in load might increase weekday unit commitment but not impact weekend operations. Second, identify what fraction of time different types of units would be next in line to be started or shut down in response to a change in load. Third, rely on engineering estimates to establish the fixed fuel costs for each type of unit. With this information, the fixed fuel cost adjustment can be estimated by taking the product of the probability of particular units being next in line times the fixed fuel cost for each unit. The fixed fuel cost can be allocated to time period by investigating how changes in load by costing period affect production scheduling. A simple approach would be to identify the probability of different costing periods being the peak, and using these probabilities to allocate fixed fuel costs to costing periods.

B. Allocation of Costs to Customer Group

Marginal energy costs vary among customer groups as a result of differences in the amount of energy losses between generation level and the point in the transmission/distribution system where power is provided to the customer. Energy losses tend to increase as power is transformed to successively lower voltages, so energy losses (and thus marginal energy costs) are greatest for customer groups served at lower voltages. Ideally, energy losses should be time-differentiated and should reflect incremental losses associated with a change in customer usage, rather than average losses, although incremental losses are difficult to measure and are seldom available. Table 9-2 shows marginal energy costs by customer group, taking into account time-differentiated average energy losses for the utility case study. The variation in average marginal energy costs in Table 9-2 is due solely to differences in energy losses, reflecting differences in service voltage among the customer groups.

TABLE 9-2

MARGINAL ENERGY COSTS
BY TIME PERIOD AND RETAIL CUSTOMER GROUP

(¢/KWH, at Sales Level)

	Summer			Winter		
Customer Group	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak
Residential	4.18	3.00	2.70	3.68	3.05	2.86
Commercial	4.17	2.99	2.69	3.68	3.05	2.85
Industrial	4.08	2.94	2.64	3.57	2.96	2.80
Agriculture	4.18	3.00	2.70	3.68	3.05	2.86
Street Lighting	4.13	2.97	2.67	3.63	3.01	2.83

II. MARGINAL CAPACITY COSTS

In most utility systems, generating facilities are added primarily to meet the reliability requirements of the utility's customers.[7] These generating facilities must be capable of meeting the demands on the system with enough reserves to meet unexpected outages for some units. System planners employ deterministic criteria such as reserve margin standards (e.g., 20 percent above the forecast peak demand) or probabilistic criteria such as loss of load probability (LOLP) standards (e.g., one outage occurrence in ten years). Whichever approach is used, these standards implicitly reflect how valuable reliability is to utility customers. Customers are willing to pay for reliable service because of the costs that they incur as a result of an outage. More generally, this is referred to as shortage cost, including the cost of mitigating measures taken by the customer in addition to the direct cost of outages. Reasonable reliability standards balance the cost of improving reliability (marginal capacity cost) with the value of this additional reliability to customers (shortage cost).

[7] In some systems that rely heavily on hydro facilities, energy may be a constraining variable rather than capacity. New generating facilities are added primarily to generate additional energy to conserve limited water supplies. In such circumstance, marginal capacity costs are essentially zero.

A. Costing Methodologies

There are two methodologies in widespread use for determining marginal capacity costs, the peaker deferral method and the generation resource plan expansion method. The peaker deferral method uses the annual cost of a combustion or gas turbine peaker (or some other unit built solely for capacity) as the basis for marginal capacity cost. The generation resource plan expansion method starts with a "base case" generation resource plan, makes an incremental or decremental change in load, and investigates how costs change in response to the load change.

1. Peaker Deferral Method

Peakers are generating units that have relatively low capital cost and relatively high fuel costs and are generally run only a few hours per year. Since peakers are typically added in order to meet capacity requirements, peaker costs provide a measure of the cost of meeting additional capacity needs. If a utility installs a baseload unit to meet capacity requirements, the capital cost of the baseload unit can be viewed as including a reliability component equivalent to the capital cost of a peaker and an additional cost expended to lower operating costs. Thus, the peaker deferral method can be used even when a utility has no plans to add peakers to meet its reliability needs. The peaker deferral method measures long-run marginal cost, since it determines marginal capacity cost by adding new facilities to just meet an increase in load, without considering whether the existing utility system is optimally designed. The peaker deferral method compares the present worth cost of adding a peaker in the "test year" to the present worth cost of adding a peaker one year later. The difference is the annual (first-year) cost of the peaker. This cost is adjusted upward since, for reliability considerations, more than one MW of peaker capacity must be added for each MW of additional customer demand.[8] In the utility case study, the installed capital cost of the peaker is $615/KW, resulting in a marginal capital cost of $80/KW. Details on the derivation of this latter figure are provided in Appendix 9-A.

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[8]The peaker deferral method is described in greater detail in National Economic Research Associates, A Framework for Maginal Cost-Based Time-Differentiated Pricing in the United States: Topic 1.3, Electric Utility Rate Design Study, February 21, 1977.

2. Generation Resource Plan Expansion Method

An alterntive approach to developing marginal production cost is to take the utilion resource plan as a base case, and then increment or decrement the load forecast on which the plan was based. An alternate least-cost resource plan is then developed which account the modified load forecast. The resulting revision to the generation resource plan captures the effect of the change in customer usage.[9]

Similar to the peaker deferral method, the annual costs of the base case and revised generation resource plans are calculated, and then discounted to present-worth values. The annual revenue requirements include both capital-related and fuel-related costs, so fuel savings associated with high capital cost generating units are reflected in the analysis. The difference between the present-worth value of the two cases is the marginal capacity cost of the specified change in customer usage.

In the utility case study, the least-cost response to an increase in customer load in the "test year" would result in returning a currently retired generating unit to service one year sooner. The increase in total production cost (capital and fuel costs) associated with this increased load case results in a marginal capacity cost of $21/KW. The derivation of this figure is provided in Appendix 9-A. In contrast to the peaker deferral method, the generation resource plan expansion method measures short-run marginal cost, since it explicitly accounts for the current design of the utility system. In the utility case study, the presence of a temporarily out-of-service generating unit indicates surplus capacity, which accounts for the difference between short-run marginal capacity cost and long-run marginal capacity cost.

B. Allocation to Time Period

LOLP refers to the likelihood that a generating system will be unable to serve some or all of the load at a particular moment in time due to outages of its generating units. LOLP tends to be greatest when customer usage is high. If LOLP in a period is 0.01, there is a one percent probability of being unable to serve some or all customer load. Similarly, if load increases by 100 KW in this period, on average, the utility will be unable to serve one KW of the additional load. Summing LOLP over all periods in a year gives a measure of how reliably the utility can serve additional load.

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[9]The generation resource plan expansion method is described in greater detail in C. J. Cicchetti, W. J. Gillen, and Paul Smolensky, The Marginal Cost and Pricing of Electricity: An Applied Approach, June 1976.

If load increases in an on-peak period when usage is already high, the LOLP-weighted load is high and there is a relatively large impact on reliability which must be offset by an increase in generating resources. If load increases in an off-peak period when usage is low, the LOLP-weighted load is low and there may be relatively little impact on reliability. Similarly, when additional generating resources are added to a utility system, the incremental reliability improvement in each period is proportional to the LOLP in that period. Thus, LOLP's can be used to allocate marginal capacity costs to time periods. A simple example showing the derivation of LOLP and its application to allocating marginal capacity costs to time periods is shown in Appendix 9-B.

An actual allocation of marginal capacity costs to time periods is shown in Table 9-3, based on the utility case study. The LOLP's are based on a probabilistic outage model that takes into account historical forced outage rates, scheduled unit maintenance, and the potential for emergency interconnection support.

TABLE 9-3

ALLOCATION OF MARGINAL CAPACITY COST TO TIME PERIOD

Time Period	Hours	LOLP	Marginal Capacity Cost
Summer On-Peak	12:00 noon - 6:00 p.m.	0.716949	$57.31
Mid-Peak	8:00 a.m. - 12:00 noon		
	6:00 p.m. - 11:00 p.m.	0.124160	9.93
Off-Peak	11:00 p.m. - 8:00 a.m.		
	and all weekend hours	0.002532	0.20
Winter On-Peak	8:00 a.m. - 5:00 p.m.	0.054633	4.37
Mid-Peak	5:00 p.m. - 9:00 p.m.	0.087076	6.96
Off-Peak	9:00 p.m. - 8:00 a.m.		
	and all weekend hours	0.014650	1.17

C. Allocating Costs to Customer Groups

Marginal capacity costs vary by customer group, reflecting differences in losses between generation level and the point where the power is provided to the customer (sales level). Ideally, the loss factors used to adjust from sales to generation level should reflect incremental losses rather than simply reflecting average energy losses, although incremental losses are difficult to measure and are seldom available.

Table 9-4 shows marginal capacity costs by rating period, reflecting losses by customer group, based on the utility case study. This table is constructed for illustration only, by assuming that each customer group's usage is constant for all hours within the rating periods shown. In actuality, the revenue allocation described in Chapter 11 uses hourly customer group loads and hourly LOLP data to calculate hourly marginal capacity costs by customer group.

TABLE 9-4

AVERAGE MARGINAL CAPACITY COSTS BY RATING PERIOD AND RETAIL CUSTOMER GROUP

($/KW month)

	Summer (4 Months)			Winter (8 Months)			
Customer Group	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Annual
Residential	15.86	2.74	0.06	0.60	0.96	0.16	88.32
Commercial	15.79	2.72	0.06	0.60	0.96	0.16	87.96
Industrial	15.46	2.67	0.06	0.59	0.94	0.16	86.12
Agriculture	15.86	2.74	0.06	0.60	0.96	0.16	88.32
Street Lighting	15.69	2.71	0.06	0.60	0.95	0.16	87.36

In general, all customers receive the same level of reliability from the generation system, since it is seldom practical to provide service at different reliability levels. Sometimes customers are served under interruptible tariffs or have installed load management devices, however, which effectively provide a lower reliability service. The marginal capacity cost for these customers may be zero if the utility does not plan for, or build, capacity to serve the incremental load of these customers. If the utility continues to plan for serving these customer loads, but with a lower level of reliability, the marginal capacity cost for these customers is related to the marginal capacity cost for regular customers by their relative LOLP's.

APPENDIX 9-A

DERIVATION OF MARGINAL CAPACITY COSTS USING THE PEAK DEFERRAL AND GENERATION RESOURCE PLAN EXPANSION METHODS

This appendix provides an example of the application of the peaker deferral method and the generation resource plan expansion method to calculating marginal capacity cost.

A. Peaker Deferral Method

The peaker deferral method is described in greater detail in Topic 1.3 of the Electric Utility Rate Design Study, A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States (National Economic Research Associates, February 21, 1977). This method begins with a forecast of the capital and operating costs of a peaker.

Based on the capital and operating costs of a peaker, a future stream of annual revenue requirements is forecast over the expected life of the peaker and its future replacements. Next, this stream of annual revenue requirements is discounted to a single present-worth value using the utility cost of capital.[10] Next, the annual stream of revenue requirements is shifted forward assuming that construction of the peaker and its future replacements is deferred one year, and the resulting stream of revenue requirements is discounted to a single present-worth value. The difference between these two present-worth values is the deferral value -- the "cost" of operating a peaker for one year. Finally, this deferral value must be scaled upward to reflect that a peaker is not perfectly reliable, and may not always be available to meet peak demands. This can be done by comparing the reliability improvement provided by a "perfect" resource (one that is always available) to the reliability improvement provided by a peaker. This ratio, sometimes called a capacity response ratio (CRR), is then multiplied by the peaker deferral value to calculate marginal capacity cost.

[10] Arguably, a ratepayer discount rate may be more appropriate than the utility's cost of capital. Due to the difficulty of developing a ratepayer discount rate, utility cost of capital is commonly employed for discounting. The cost of capital should be based on the cost of acquiring new capital. This will generally differ from the authorized rate of return, which reflects the embedded cost of debt financing.

A calculation of marginal capacity cost using the peak deferral method is illustrated in Table 9A-1, based on the utility case study. The calculation starts with the installed capital cost of a combustion turbine, including interconnection and appurtenant facilities and capitalized financing costs, of $614.97/KW.

TABLE 9A-1

DEVELOPMENT OF MARGINAL PRODUCTION COST USING THE PEAKER DEFERRAL METHOD

Line No.	Item	$/KW
1	Peaker Capital Cost	614.97
2	Deferral Value (Line (1) x 10.07%)	61.93
3	Operation and Maintenance Expense	6.39
4	Fuel Oil Inventory Carrying Cost	1.19
5	Subtotal (Line (2) + Line (3) + Line (4))	69.51
6	Marginal Capacity Cost (Line (5) x 1.15)	79.94

This initial capital investment (line 1) is then multiplied by an economic carrying charge of 10.07 percent to give the annual deferral value of the peaker (line 2). The economic carrying charge is conceptually similar to the levelized carrying charge which is frequently used in evaluating utility investments. While a levelized carrying charge produces costs which are level in nominal dollars over the life of an asset, the economic carrying charge produces costs which are level in inflation-adjusted dollars.[11] The economic carrying charge is the product of three components, as shown in the following equation:

Economic carrying charge = revenue requirement present-worth factor
x infinite series factor
x deferral value factor

The revenue requirement present-worth factor is calculated based on the initial capital investment as follows. A projection of annual revenue requirements associated with the $614.97/KW initial investment is made for the life of the investment. Included

[11]The development of the economic carrying charge in this section ignores the effect of technological obsolescence. The effect of incorporating technological obsolescence would be costs that decline over time (in inflation-adjusted dollars) at the rate of technological obsolescence (see Attachment C, "An Economic Concept of Annual Costs of Long-Lived Assets" in National Economic Research Associates, *op. cit.*).

in these annual revenue requirements are depreciation, return (using the cost of obtaining new capital), income taxes, property taxes, and other items which may be attributed to capital investment. These annual revenue requirements are then discounted using the utility's cost of capital, producing a result perhaps 30 to 40 percent above the initial capital cost, depending largely on the utility's debt-equity ratio and applicable tax rates. The ratio of the discounted revenue requirements to the initial capital investment is the revenue requirement present-worth factor.

The next component in the economic carrying charge calculation increases the discounted revenue requirements to reflect the discounted value of subsequent replacements. The simplest approach is to use an infinite series factor. Assuming that capital costs rise at an escalation rate i, that the utility cost of capital is r, and that peakers have a life of n years, the formula is as follows:

$$\text{Infinite Series Factor} = \frac{1}{1 - \left(\frac{1+i}{1+r}\right)^{n}}$$

The final component of the economic carrying charge is the deferral value factor. If the construction of the peaker is deferred by one year, each annual revenue requirement is discounted an additional year, but is increased due to escalation in the capital cost of the peaker and its replacements. The value of deferring construction of the peaker for one year is given by the difference between the discount rate and the inflation rate, expressed in original year dollars, as follows:

$$\text{Deferral Value Factor} = \frac{r-i}{1+r}$$

The next step in the calculation of marginal capacity cost is to add annual expenditures such as operation and maintenance expenses (line 3), and the cost of maintaining a fuel inventory (line 4). Finally, the subtotal of these expenses (line 5) is multiplied by a capacity response ratio, accounting for the reliability of the peaker compared with a perfect capacity resource, to give the marginal capacity cost (line 6).

The peaker deferral method produces a measure of long-run marginal cost, since it measures the cost of changing the utility's fixed assets in response to a change in demand, without taking into account a utility's existing capital investments.

Using a probabilistic outage model, loss of load probability (See Appendix 9-B) can be used to adjust long-run marginal costs developed from a peaker deferral method to reflect short-run marginal costs. This is accomplished by multiplying the marginal capacity cost from the peaker deferral method times the ratio of forecast LOLP to the LOLP planning standard. This can be seen in the following example. If the LOLP planning standard is 0.0002, then a 10,000 KW increase in demand will, on average, result in an expected 2 KW being unserved. Since this is the planning standard, the value to consumers of avoiding these 2 KW being unserved is just equal to the cost of adding an addiin demand will, on average, result in 1 KW being unserved. Adding an additional resource would benefit consumers, but only an expected 1 KW of unserved demand would be avoided. Thus, the benefit of avoiding the 1 KW of unserved load is one-half the cost of the additional resources necessary to serve this load. In this example, short-run marginal capacity cost is one-half the long-run marginal capacity cost.

B. Generation Resource Plan Expansion Method

The generation resource plan expansion method is described in greater detail in The Marginal Cost and Pricing of Electricity: An Applied Approach (C. J. Cicchetti, W. J. Gillen, and Paul Smolensky, June 1976). This method begins with the utility's current least-cost resource plan, increments or decrements load in the "test year" by some amount, and revises the least-cost resource plan accordingly. The present-worth cost of the two resource plans, including both capital and fuel costs, are compared, and the difference represents the marginal capacity cost for the chosen load increment.

The generation resource plan expansion method can be illustrated using the utility case study. In this case study, the utility has adequate resources to serve loads and, in addition, has surplus oil/gas units which are expected to be refurbished and returned to service to meet future load requirements. If load were to increase above forecast, this would accelerate the refurbishment of these units. For example, if load increased 200 MW, the refurbishment and return to service of a 225 MW unit would be advanced one year. The cost of this refurbishment is about $30 million and would result in perhaps a 15-year life extension. For simplicity, the annual cost of accelerating the capacity requirement is computed using the same economic carrying charge approach as developed above for the deferral of a peaker as follows:[12]

$$\text{Annual Cost (\$/KW)} = \frac{\text{(Capital Cost) x (Economic Carrying Charge)}}{\text{(Load Increment)}}$$

$$= \frac{(\$30{,}000{,}000) \times (0.1407)}{(200{,}000 \text{ KW})}$$

$$= \$21/\text{KW}$$

[12]The economic carrying charge is actually higher since the 15-year life extension is shorter than the expected 30-year life of the peaker. It would be more precise to identify the replacement capacity for the refurnished unit in the resource plan when it is eventually retired after 15 years, and take into consideration the effect of acclerating the unit's return to service on this furture replacement.

This annual cost should be reduced by the annual benefit of any fuel savings resulting from the accelerated return to service of the unit. However, a production cost model analysis shows that there are virtually no fuel savings from returning the unit to service, since its operating costs are about the same as for the oil/gas units already in service.

In implementing this generation resource plan method, care must be taken to choose load increments that do not lead to lumpiness problems. If the load increment is small, there may not be an appreciable impact on the generation resource plan. On the other hand, a modest load change may be sufficient to tilt the scales toward a new generating resource plan, overstating the effect of the load change in general. One approach to dealing with potential lumpiness problems is to investigate a series of successive load increments, and then take an average of the marginal capacity costs determined for the successive increments.

Comparing this result with the peaker deferral method, the utility's short-run marginal capacity cost of $21/KW is about 26 percent of the long-run marginal capacity cost of $80/KW associated with meeting the capacity requirements by adding new generating facilities.

APPENDIX 9-B

A SIMPLE EXAMPLE OF THE DERIVATION OF LOSS OF LOAD PROBABILITIES

This appendix provides a simple example of how LOLP is developed and used to allocate marginal capacity costs to time periods. In the example shown in Table 9B-1, there are two time periods of equal length: an on-peak period where load is 250 MW and an off-peak period where load is 150 MW. The utility has four generating units totaling 600 MW, with various forced outage rates. Table 9B-1 calculates the probability of each combination of the four units being available. For example, there is a 0.0004 probability that all of the units are out of service simultaneously. Similarly, there is a 0.0324 probability that Units C and D are available (0.9 probability that each unit is available) while Units A and B are not available (0.1 probability that each unit is in a forced outage). Thus, there is a 0.0004 probability that the utility would be unable to serve any load, a 0.0076 probability that the utility would be unable to serve loads above 100 MW, a 0.0432 probability that the utility would be unable to service loads above 200 MW, and so forth. When load is 150 MW in the off-peak period, the utility will be unable to serve this load if all four units are not available, if only Unit C is available, or if only Unit D is available. The probability of these events occurring is 0.0076. Similarly, the probability of being unable to serve the 250 MW load in the on-peak period is 0.0432. The overall LOLP is 0.0508, with 85 percent of this LOLP resulting from the on-peak period. Thus, 85 percent of the marginal capacity costs are allocated to the on-peak period and 15 percent to the off-peak period.

TABLE 9B-1
LOSS OF LOAD PROBABILITY EXAMPLE

Resources:

Size	Forced Outage Rate	Expected Availability
A: 200 MW	20%	80%
B: 200 MW	20%	80%
C: 100 MW	10%	90%
D: 100 MW	10%	90%

Probabilities:

Units	MW Available	Available Probability	Cumulative Probability
None	0	(.2)(.2)(.1)(.1)=0.0004	0.0004
C	100	(.2)(.2)(.9)(.1)=0.0036	0.0040
D	100	(.2)(.2)(.1)(.9)=0.0036	0.0076
A	200	(.8)(.2)(.1)(.1)=0.0016	0.0092
B	200	(.2)(.8)(.1)(.1)=0.0016	0.0108
C, D	200	(.2)(.2)(.9)(.9)=0.0324	0.0432
A, C	300	(.8)(.2)(.9)(.1)=0.0144	0.0576
A, D	300	(.8)(.2)(.1)(.9)=0.0144	0.0720
B, C	300	(.2)(.8)(.9)(.1)=0.0144	0.0864
B, D	300	(.2)(.8)(.1)(.9)=0.0144	0.1008
A, B	400	(.8)(.8)(.1)(.1)=0.0064	0.1072
A, C, D	400	(.8)(.2)(.9)(.9)=0.1296	0.2368
B, C, D	400	(.2)(.8)(.9)(.9)=0.1296	0.3664
A, B, C	500	(.8)(.8)(.9)(.1)=0.0576	0.4240
A, B, D	500	(.8)(.8)(.1)(.9)=0.0576	0.4816
A, B, C, D	600	(.8)(.8)(.9)(.9)=0.5184	1.0000

Time Period Demand:

		LOLP	
On-Peak	250 MW	0.0432	85%
Off-Peak	150 MW	0.0076	15%
		0.0508	

CHAPTER 10

MARGINAL TRANSMISSION, DISTRIBUTION AND CUSTOMER COSTS

In contrast to marginal production costing methodology, analysts have devoted little attention to developing methodologies for costing marginal transmission, distribution and customer costs. An early evaluation noted: "... the determination of marginal costs for these functions, and especially distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort."[1] The referenced study, therefore, used average embedded costs, because they were both more familiar to ratemakers and analysts, and a reasonable approximation to the marginal costs. It is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. While marginal cost concepts have been applied to transmission and distribution for the purpose of investigating wheeling rates, little of this analysis has found its way into the cost studies performed for retail ratemaking. The basic research into marginal costing methodologies for transmission, distribution and customer costs for retail rates was done in connection with the 1979-1981 NARUC Electric Utility Rate Design Study and most current work and testimony still refer back to those results.

I. TRANSMISSION

There are several basic approaches to the calculation of the marginal cost of transmission. However, the first step in any approach is the definition of the study period. Transmission investments are "lumpy" in that they usually occur in large amounts at intervals. Therefore, it is important to select a study horizon that is long enough to reflect the relationship between investments and load growth. To the extent that investments are related to load growth occurring outside the study period or there is

[1] J. W. Wilson, Report for the Rhode Island Division of Public Utilities, Public Utilities Commission and Governor's Energy Office (1978), pp. B-27-8.

a significant change in the level of system reliability, the analyst may wish to adjust the calculation of the load growth to identify the investment more closely with the load it is intended to serve. Given the desirability of a fairly long study period, analysts will typically select the utility's entire planning period augmented by historical data to the extent that the analyst believes that the historical relationships will continue to obtain in the future.

For purposes of a marginal cost study, investment in the transmission system is generally assumed to be driven by increments in system peak load. As the transmission system was actually constructed for a variety of reasons, the second step in the calculation of the marginal cost of transmission is to identify and eliminate those investments that are not related to load growth. The non-demand related transmission investments can be categorized as:

1. Those related to remote siting of generation units (which are costed as part of the generation cost).
2. Those related to system interconnections and pool requirements (whose benefits are manifested in reduced reserve requirements and, therefore, are again costed with generation).
3. Those associated with large loads of individuals (which are therefore charged to the particular customer concerned).
4. Replacement of existing facilities without adding capacity to serve additional load (assuming that the economic carrying charge formula incorporates an infinite series factor).

Costs that remain should be related only to system load growth or to maintenance of system reliability.

A. Costing Methodologies

There are two basic approaches to estimating marginal transmission costs, and they begin to diverge at this step in their methodology. The first approach is the Projected Embedded Analyses of which there are two variations: the Functional Subtraction approach, which relates total transmission investment additions to load growth, and the Engineering approach, which relates individual facilities (line miles, transformers, etc.) to load growth. The second methodology is the System Planning approach, which uses a base case/decrement analysis.

1. Projected Embedded Analyses

As the name suggests, Projected Embedded Analyses are often based on a simple projection of past costs and practices into the future. A disadvantage of this approach is that it may fail to capture important technological and business related developments and therefore result in the over or underestimation of marginal capacity cost.

- Functional Subtraction Approach

The Functional Subtraction approach requires data in the form of annual load related investments in transmission and load growth for the same period. The period to be analyzed includes the transmission planner's planning period plus whatever historical period he believes appropriate. Transmission cost data must be sufficiently specific to enable the analyst to differentiate load growth related transmission expenditures from those more properly associated with either generation or a specific customer. Having chosen the study period and identified the load related investments in transmission by voltage level, the analyst performs the analysis in real dollars. This is done by converting the historical nominal data to current money values by applying either the Handy-Whitman plant costs indices or, if available, an inflation index particular to the utility. Projected investments are converted to real dollars by removing the inflation factor used by the planner in his computations.

The third step is to relate the real transmission investments to a measure of load growth at each voltage level, weather normalized if possible, stated in kilowatts. Non-coincident peak demand on the transmission system is the correct measure of load growth. However, given the system's integrated nature, for most purposes non-coincident peak demand on the transmission system is the same as the total system coincident peak.

The relationship between investment and load growth ($/KW) is usually obtained by simply dividing the sum of investments for the period by the growth in peak load. There have been some attempts at regressing annual investments against load growth, using the equation Transmission Costs = a + b (peak demand), but the R^2's have been disappointingly low. However, given the assumption that transmission investments are "lumpy" and that one particular year's investment is not specifically related to that year's load growth, the lack of correlation should not be surprising. The best regression results are achieved by using least squares and regressing cumulative incremental investment against cumulative incremental load. Thus, the first year observation is the first year value of incremental investment and load, the second year observation is the sum of the first year and the second year values, the third year is the sum of the values for the first three years, and so on. See Table 10-1.

TABLE 10-1
Computation of Marginal Demand Cost of Transmission
Transmission-Related Additions to Plant
Per Added Kilowatt of Transmission System Peak Demand
(Functional Subtraction Approach)

Year	(1) Growth Related Net Addition (1988 $M)	(2) Cumulative Net Addition (1988 $M)	(3) Growth In System Peak (MW)	(4) Cumulative System Peak (MW)
Actual				
1976	44.1	44.1	888	888
1977	33.8	78	166	1054
1978	40	118	750	1804
1979	30	147.9	467	2271
1980	36.4	184.3	148	2419
1981	30.6	214.9	808	3227
1982	134.2	349.1	(538)	2689
1983	62.7	411.8	295	2984
1984	42.5	454.3	1685	4669
1985	148.3	602.6	(579)	4090
Projected				
1986	188.6	791.2	21	4111
1987	71.4	862.6	302	4413
1988	178.5	1041	446	4859
1989	83.6	1124.7	406	5265
1990	128.7	1250.4	407	5672
Total:	1250.4		5672	

Simplified Approach

Marginal Transmission Investment Costs = Column 1 Total/Column 3
Total = $220.45/KW

Regression Approach

Marginal Transmission Investment Costs = $249.40/KW

Y = A + B*X
Where Y is cumulative demand-related net additions to plant
X is cumulative additions to coincident peak demand.

A = -326.59
B = 0.2494

R^2 = 0.84

The fourth step is to convert the per kilowatt investment cost into an annualized transmission capacity cost by multiplying the former by a carrying charge rate. There are two forms in common use, the economic carrying charge and the standard annuity formula. During a period of zero inflation the two methods produce the same results, but during inflationary periods only the former takes due account of the impact of inflation on the value of plant assets.[2]

Since the addition of transmission capacity occasions increased operation and maintenance expenses, the marginal 0&M costs are calculated and added to the annualized transmission capacity costs. The expense per KW is usually found to be fairly constant and either the current year's expense or the average of the $/KW in current dollars over the historical portion of the study period is considered to be a good approximation of the marginal transmission operation and maintenance expense. The analyst takes the data from the FERC Form I, again being careful to include only those costs related to load growth. For example, he may exclude rents or that portion of expenses related to load dispatching associated with generation trade-offs. Total transmission 0&M expenses in current dollars are divided by system peak demand, and averaged if multiple years have been used. The result, either for the single current year or the average of several years, is then added to the annualized transmission capacity cost to obtain the total transmission marginal cost. Alternatively, 0&M expenses can be regressed on load growth or transmission investments, in which case the 0&M adjustment appears as a multiplier to the capacity cost rather than an adder.

The final step is to adjust the results for transmission's share of indirect costs including the marginal effect on general plant and working capital. See Table 10-2.

TABLE 10-2
Computation of Marginal Demand Costs of Transmission
(1988 $)

Description	Cost Per KW ($)
Transmission Investment per KW Change in Load (from Table 10-1)	249.40
Annual Costs (*10.9%)	27.18
Demand Related O&M Expense	4.52
General Plant Loading	1.05
Working Capital	0.48
Total Annual Cost of Transmission	33.23
Loss Adjustment (1.033)	34.33

[2]See Appendix 9-A for the derivation of the economic carrying charge.

o Engineering Approach

Like Functional Subtraction, the Engineering approach also relates changes in transmission investment to changes in system peak load. However, it first relates the addition of specific facilities (line miles, transformers, etc.) to growth in load over the chosen study period, and then computes the unit costs of each facility to derive the investment for transmission per added kilowatt of demand. The method has the advantage of more readily identifying those facilities added for the purpose of serving added load (and thereby excluding non-load related investment). It may be more difficult to apply, however, as it requires detailed records and distinctions that may come more easily to the utility company planner than to the outside observer.

Once the study period is selected, the analyst identifies the load growth related facilities that were or will be added each year at each voltage level. By either regression analysis or simple averages, the addition of facilities is related to the growth in coincident system peak. The result is expressed in line miles, transformers, etc. per added KW and monetized by applying a cost figure for each facility in real dollars. As with Functional Subtraction, the investment per added demand is annualized by a levelized carrying charge, or, more properly, an economic carrying charge (consistent with calculations for the other capacity components) and added to the associated annual operation and maintenance costs. The costs per KW for each facility are then totaled at each voltage level and adjusted for indirect costs.

2. The System Planning Approach

The System Planning approach is more nearly related to the marginal costing methodologies for generation than is the Projected Embedded approach. As such, it may be helpful to review what is meant by marginal capacity cost. The marginal cost of transmission or distribution capacity can be defined as the present worth of all costs, present and future, as they would be with a demand increment (decrement), less what they would be without the increment (decrement). This definition of marginal cost can be represented by a time-stream of discounted annual difference costs stretching to infinity. The stream of investments from this approach would be annualized by using an economic carrying charge.

Alternatively, the marginal capacity cost can be interpreted as the cost to the utility of bringing forward (delaying) by one year its future investments, including the stream of replacement investments, to meet the demand increment (decrement). Mathematically, this interpretation results in annual charges equal to the economic carrying charge on the marginal investments.

In order to simplify the calculation of marginal capacity cost it is common for the stream of difference costs to be truncated after a set number of years, usually the utility's planning period or the average economic life of the investments. However, if the period chosen is too short, truncation can result in serious underestimation of marginal capacity cost. In terms of the second definition this would be equivalent to neglecting the impact of the increment (decrement) on more distant investments. Truncating a component of the economic carrying charge as discussed in Appendix 9-A will mitigate some of those effects.

The System Planning approach is an application of the first incremental/decremental definition of marginal capacity cost and therefore the analyst should take care not to base his calculations on an unreasonably short planning horizon.

In contrast to the projected embedded studies for transmission cost, which may use some historical data, the study period for the system approach is forward-looking. As with the other methodologies, the relevant costs are those related to changes in load, and coincident system peak is the basic cost causation factor. The data required is thus the planner's base case of expected load growth and transmission investments, plus an incremental (decremental) case for the same period.

Planned transmission costs, investment and expenses, are identified and the marginal cost quantified by developing a differential time series of expenditures over the planning horizon using an increment or decrement to system peak load. A base case expansion plan is developed using the forecasted load over the future planning horizon. Investments are separated by voltage level where the utility has customers who take service directly from the high voltage lines. Those investments associated with load growth are identified and the total annual revenue requirements (including expense items) are derived in real or nominal dollars for each year at each voltage level.

The system planner is then asked to assume an increase or decrease in the coincident peak load and redesign transmission expenditures, still maintaining system reliability and continuing to meet the system planning criteria, and repeat the costing procedure. Thus, the marginal transmission capacity cost is the change in total costs associated with changes to budgeted transmission expenditures between the planner's base case and his incremental (decremental) case. The dollar stream representing the difference between the two cases is present worthed, aggregated and then annualized over the costing horizon. The resultant annualized figure is then divided by the amount of the increment (decrement) to obtain a $/KW marginal cost for transmission for each voltage level. The size of the increment (decrement) may vary according to the size of the utility and will certainly affect the result. A 50 MW change is often chosen as the smallest (most marginal) change that can be assumed and produce measurable differentiated cases.

3. Adjustments

- Loss Adjustment

Electric utility transmission and distribution systems are not capable of delivering to customers all of the electricity produced at the generation bus bar. The difference between the amount of electricity generated and the amount actually delivered to customers is called "losses".

Losses can be broadly classified as copper losses, core losses and dielectric losses. They are caused, respectively, by the production of heat, the establishment of magnetic fields and the leakage of current. The first of these varies in proportion to the square of the current and is therefore included under marginal energy costs. The latter two are fixed losses associated with specific equipment and therefore covered by marginal capacity costs.

Marginal capacity loss factors are applied to marginal capacity-related costs per kilowatt. These factors account for the fact that when a customer demands an additional kilowatt at the meter, more than a kilowatt of distribution, transmission and generation capacity must be added.

- Energy Adjustment

While most analysts assume that transmission is causally related to system peak and therefore is totally demand related, it has been argued, particularly in the literature concerning wheeling rates, that transmission embodies an energy component as well. For very small changes in load, transmission and generation are substitutes: additional generation can overcome the line losses in the transmission system, or extra transmission capacity can, by reducing losses, substitute for added generation. Thus, conceptually, it is proper to net out the energy savings from the marginal investment cost of transmission, leaving the residual to be demand related. There is no accepted methodology for quantifying this adjustment. One approach is to obtain a calculation of the energy loss/potential savings in $/period by multiplying the cost of 1 KW for each costing period times the energy loss in that period. Summing across the periods produces, in total dollars per kilowatt-year, the avoidable loss/potential savings. As some of this loss occurs at the generation level, it is appropriate to net out the portion of energy loss due to generation. The remainder is net energy savings in $/KW year attributable to increased transmission capacity that can then be capitalized into a $/KW computation.

B. Allocation of Costs to Time Periods

The attribution of marginal demand-related costs by time of use reflects the system planner's response to the goal of maintaining a target level of reliability in the generation, transmission and distribution components of the system. Thus, as the load varies according to time periods, so does the need to add capacity to maintain reliability. System planners evaluate generation, transmission and distribution components separately for their reliability, and ideally the transmission capacity cost responsibility would reflect the planner's sensitivity to such factors as the likelihood of weather related service disruptions. For costing purposes, however, most analysts use the same methodologies, and often the same attribution factors, for transmission as they do for generation. The reasoning is that in general the load characteristics of the transmission system are identical to those of the generation system, both being driven by the system coincident peak. Therefore, it is not considered necessary to perform transmission specific load studies as the results of such studies should not differ significantly from those of the generation load studies. To the extent that the transmission and generation load characteristics do differ, the methodology discussed under "Distribution" can be employed.

The methods employed, include attributing the costs uniformly across the peak period, or by means of transmission reliability indicies or loss of load probability (LOLP). However, where the LOLP data are heavily influenced by seasonal generation availability (e.g., hydro facilities) or generation maintenance schedules, the generation LOLP factors are not a good measure of the need to add transmission capacity.

None of the generation-tied allocation methods recognize the seasonal variation in the capability of transmission facilities. Transmission facilities have a lower carrying capability when ambient temperatures are high (i.e., summer). Therefore, winter peaking utilities and summer peaking utilities with significant winter peaks need some method for adjusting seasonal assignment factors if they are going to rely on generation related costing allocators for transmission.

II. DISTRIBUTION

A. Costing Methodologies

The major issue in establishing the marginal cost of the distribution system is the determination of what portion of the costs, if any, should be classified as customer related rather than demand and energy related. The issue is a carry-over of the unresolved argument in embedded cost studies with the added query of whether the distribution costs usually identified as customer related are, in fact, marginal.

Most analysts agree that distribution equipment that is uniquely dedicated to individual customers or specific customer classes can be classified as customer rather than demand related. Customer premises equipment (meters and service drops) are generally functionalized as customer rather than distribution costs and, in reality, this is the only equipment that is directly assignable for all customers, even the smallest ones. Beyond the customers' premises, however, there are distribution costs that may be classified as customer related. For example, some jurisdictions classify line transformers as customer-related often using a proxy based on average load as the allocation factor when this equipment is not uniquely dedicated to individual customers. In addition, for very large customers, more than merely meters, services, and transformers are directly assignable. Some have entire substations dedicated to them. As noted above in "Transmission," distribution costs of equipment dedicated to individual customers can be directly assigned to them, thus reducing the common distribution costs assigned to the remainder of the class.

The major debate over the classification of the distribution system, however, concerns the jointly used equipment rather than the dedicated equipment. At the margin, there is symmetry between the cost of adding one customer and the cost avoided when losing one customer. A number of analysts have argued, and commissions have accepted, that the customer component of the distribution system should only include those features of the secondary distribution system located on the customer's own property. Portions of the distribution system that serve more than one customer cannot be avoided should one customer cancel service. Similarly, if the customer component of the marginal distribution cost is described as the cost of adding a customer, but no energy flows to the system, there is no reason to add to the distribution lines that serve customers collectively or to increase the optimal investment in the lines that are carrying the combined load of all customers. Therefore, the marginal customer cost of the jointly used distribution system is zero.

Those analysts who believe that there is a significant customer component to the marginal cost of the jointly used portion of the distribution system argue that the distribution system is causally related to increases in both the number of customers and the kilowatts of demand. (They may also note that distribution costs are influenced by the concentration of such non-demand, non-customer factors as load, geographic terrain, climatic conditions and local zoning ordinances. However, no analyst has attempted to introduce and quantify these elements in a marginal cost of service study and absent area-specific rates depending on density and distance from load centers, there is no reason to do so.) Because of the non-interconnected character of the distribution system, the relevant demand parameter is non-coincident peak, preferably measured at the individual substation or even at lower voltages, rather than the system peak used for generation and transmission. This reflects the fact that each portion of the distribution network must be planned to serve the maximum load occurring on it and the utility's investment reflects the need to provide capacity to each separate load center. As some customers receive service directly from the primary distribution system, calculations must be performed separately for the different voltage levels.

The measured relationship for each voltage level is expressed by the equation:

Total Distribution Cost = a + b x demand on distribution + c x customers

The statistical difficulty with this equation is that the demand is highly correlated with the number of customers (multicollinearity) and that therefore it is not possible to identify the separate marginal effects of changes in demand and customers on cost. The proposed estimation techniques resolve the statistical dilemma by computing the customer responsibility separately and then relating the residual cost to load growth. To the extent that the distribution system is sized in part to reduce energy losses, an energy component must also be netted out of marginal cost in order to obtain the demand component.

The two most common approaches to calculate the customer related component in marginal as well as embedded studies are the zero intercept method and the minimum grid calculation. The zero intercept method re-defines the original equation to read:

Total Distribution Cost = a + b x demand on distribution

It solves the multicollinearity problem by eliminating the customer variable under the hypothesis that the constant "a" will then represent the non-variable, non-demand related portion of the costs, or the distribution facilities required when demand is zero. The method has been accused of "solving" the problem of multicollinearity by mis-specifying the equation. Statistically, removing a correlated variable (customers) from the equation will result in transferring some of the responsibility of the omitted variable to the coefficient of the remaining variable (demand). Application of the technique does not necessarily lead to results that make economic sense: negative constant terms are not uncommon. The approach is somewhat more successful when used to analyze cross-sectional data where the correlation is weaker or when applied to individual items of distribution equipment.

The minimum grid approach re-designs the distribution system to determine the cost in current year dollars of a hypothetical system that would serve all customers with voltage but not power (or with minimum demand of 0.5 KW), yet still satisfy the minimum standards for pole height and efficient conductor and transformer size. The calculations can be based either on the system as a whole or on a sample of areas reflecting different geographical, service and customer density characteristics.

When applying this approach, it is necessary to take care that the minimum size equipment being analyzed is, in fact, the minimum-sized equipment available, and not merely the minimum size stocked by or usually installed by the company. To the degree that the equipment being costed is larger than a true minimum, the minimum grid calculation will include costs more properly allocated to demand.

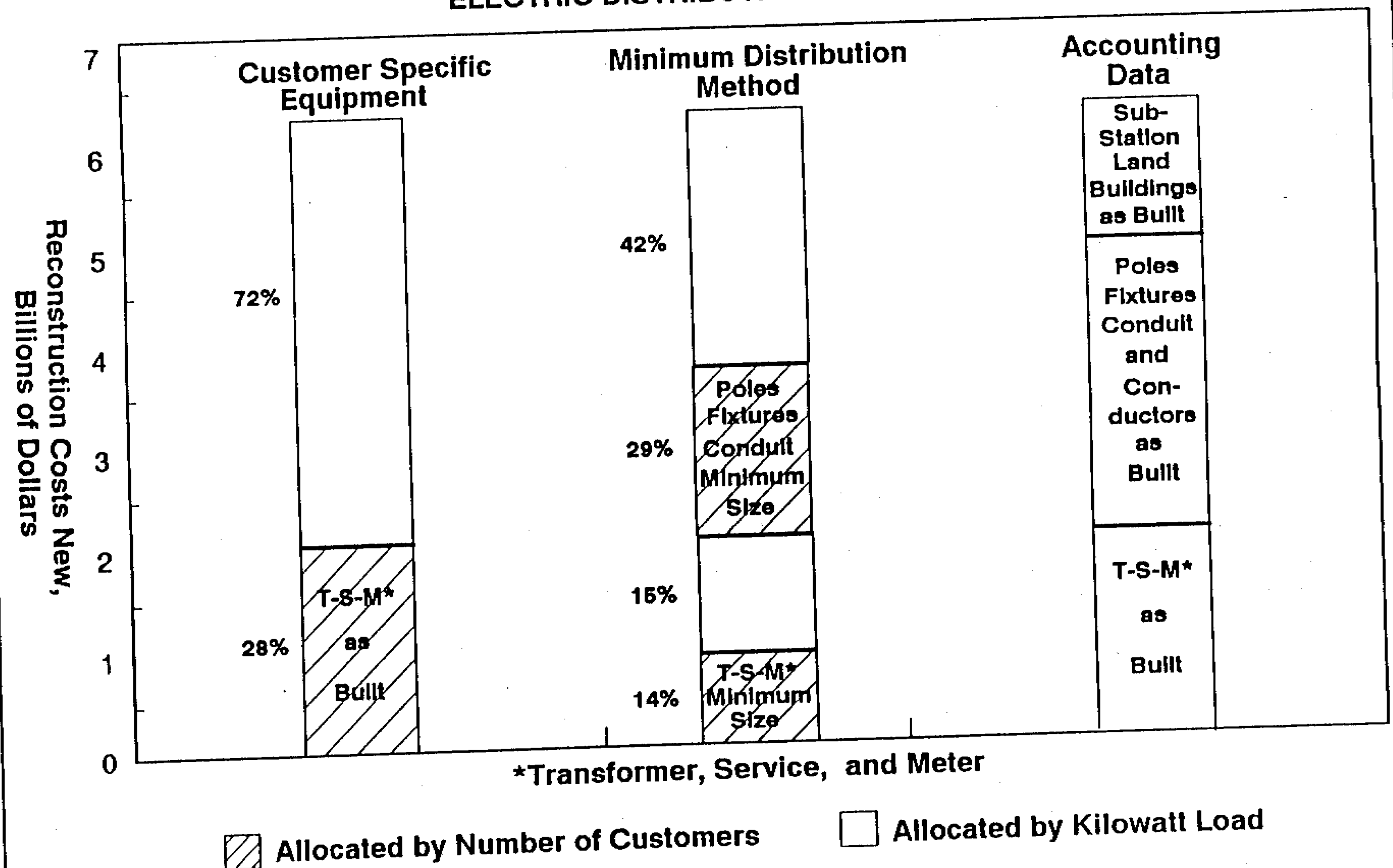
Figure 10-1 illustrates the results of the minimum grid approach for the marginal customer-related cost for a typical residential customer of the sample utility. In column 1 (Customer Specific Equipment) only line transformers, service and meters are functionalized to the customer category while all other distribution equipment is functionalized to the demand category. In column 2 (Minimum Distribution Method) all distribution equipment is first estimated at minimum size and functionalized as customer-related. The additional cost of equipment, sized to meet actual expected loads is functionalized as demand-related. For comparison, column 3 reflects the reconstruction cost for the as-built system. In the sample company, the minimum grid approach to determining the marginal customer-related cost of connecting an average customer produces a customer charge equal to 43 percent of costs of the distribution system (14 percent plus 29 percent) compared to the charge resulting from the alternative T-S-M approach, i.e., restricted to meter, service, line transformer and associated costs, which is only 28 percent of the distribution system costs.

The marginal demand related distribution costs are calculated in a manner similar to the marginal demand related transmission costs. The major differences are that, if considered appropriate, the marginal customer costs must be removed from the total costs incurred during the study period, and that the relevant load growth is non-coincident peak.

Removal of customer costs can be done in two ways. The cost of the minimum grid can be divided by the number of customers served to obtain a cost per customer to be included in the customer charge. The cost per customer at each voltage level can be multiplied by the number of customers added at each voltage level during the study period, and the sum subtracted from the total distribution investment in current year dollars. This residual is then considered the demand (or demand and energy) component of the marginal cost. Alternatively, the marginal customer costs can be removed by using a factor based on the ratio of investment in the minimum distribution grid to the investment in

Figure 10-1

DIFFERING VIEWS OF THE ELECTRIC DISTRIBUTION SYSTEM



the total distribution system, calculated over the historical period. In the example, the customer related portion of the distribution system is 43 percent leaving a demand related portion of 57 percent. See Table 10-3, Column k footnote.

Table 10-3A
Demand Related Marginal Costs of Distribution
Minmum Grid Methodology

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Year	Lines	T-M-S	Total Lines	Total Repl.	New Business Lines	Land	Subs	TOTAL	Index	Reflated Additions	Demand Related Portion	Cumul. Demand Related Portion	Cumul. Non-Coin. Peak Load Additions
1976	47.1	30.6	77.7	31.0	46.7	0.9	13.4	61.0	1.820	111.0	63.3	63.3	1078
1977	58.8	56.4	115.2	48.4	66.8	0.3	-13.0	54.1	1.675	90.6	51.7	114.9	1280
1978	58.5	63.6	122.1	44.8	67.3	0.6	7.3	75.2	1.696	127.5	72.7	187.6	2191
1979	68.1	69.7	137.8	55.1	82.7	0.5	12.3	95.5	1.422	135.8	77.4	265.0	2758
1980	73.5	56.0	132.5	82.1	50.4	0.3	18.8	69.5	1.319	91.7	52.3	317.3	2937
1981	94.0	73.2	167.2	103.7	63.5	2.2	22.2	87.9	1.197	105.2	60.0	377.3	3919
1982	90.5	65.2	155.7	96.5	59.2	0.4	31.1	90.7	1.101	99.9	56.9	434.2	3265
1983	76.6	71.6	148.2	99.3	48.9	0.0	31.6	80.5	1.079	86.9	49.5	483.7	3623
1984	91.0	104.3	195.3	130.9	64.4	3.5	23.0	90.9	1.071	97.4	55.5	539.2	5670
1985	138.8	114.0	252.8	169.4	83.4	4.3	17.7	105.4	1.092	115.1	65.6	604.8	4966
1986	153.1	106.5	259.6	174.0	85.6	11.8	76.4	173.8	1.071	186.1	106.1	710.9	4992
1987	158.7	108.2	266.9	178.8	88.1	2.1	70.5	160.7	1.038	166.8	95.1	806.0	5359
1988	161.1	108.9	270.0	178.2	91.8	0.0	31.5	123.3	1.000	123.3	70.3	876.3	5900
1989	159.6	107.7	267.3	173.7	93.6	0.5	19.1	113.2	0.961	108.8	62.0	938.3	6393
1990	168.3	113.6	281.9	186.1	93.8	1.9	26.3	122.0	0.925	114.7	65.4	1.003.6	6888

Regression Results: $Y = A + B * X$

Where Y is cumulative demand-related net additions to plant and X is cumulative additions to distribution level peak demand.

A = -134.608
B = 0.1591260869

Marginal demand costs of distribution = $159.13

(a) from study workpapers
(b) from study workpapers
(c) a + b
(d) from study workpapers: total replacements (repl.) portion of Lines and T-M-S
(e) c - d
(f) from stduy workpapers
(g) from study workpapers
(h) e + f + g
(i) Handy Whitman index
(j) h * i
(k) j * 57% (43% customer related derived from the average ratio of the mininum distribution system cost to total distribution system costs calculated in study workpapers).
(l) cumulates k
(m) cumulates peak Load additions in study workpapers

TABLE 10-3B
Demand Related Marginal Cost of Distribution
Customer Specific Equipment Methodology

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Year	Lines	Replacement Lines	New Business Lines	Land	Subs	TOTAL	Index	Reflated Additions	Cumul. Demand Portion	Cumulative Non-Coin Peak Load
1976	47.1	18.8	28.3	0.9	13.4	61.0	1.820	77.532	77.532	1078
1977	58.8	24.7	34.1	0.3	-13.0	54.1	1.675	35.845	113.377	1280
1978	58.5	23.4	35.1	0.6	7.3	75.2	1.696	72.928	186.305	2191
1979	68.1	27.2	40.9	0.5	12.3	95.5	1.422	76.361	262.666	2758
1980	73.5	47.4	29.1	0.3	18.8	69.5	1.319	63.576	326.242	2937
1981	94.0	58.3	35.7	2.2	22.2	87.9	1.197	71.940	398.182	3919
1982	90.5	56.1	34.4	0.4	31.1	90.7	1.101	72.556	470.738	3265
1983	76.6	2.0	74.6	0.0	31.6	80.5	1.079	114.590	585.328	3623
1984	91.0	61.0	30.0	3.5	23.0	90.9	1.071	60.512	645.839	5670
1985	138.8	93.0	45.8	4.3	17.7	105.4	1.092	74.038	719.877	4966
1986	153.1	102.6	50.5	11.8	76.4	173.8	1.071	148.548	868.424	4992
1987	158.7	106.3	52.4	2.1	70.5	160.7	1.038	129.750	998.174	5359
1988	161.1	106.3	54.8	0.0	31.5	123.3	1.000	86.300	1984.474	5900
1989	159.6	103.7	55.9	0.5	19.1	113.2	0.961	72.556	1157.030	6393
1990	168.3	111.1	57.2	1.9	26.3	122.0	0.925	78.995	1236.025	6888

Regression Results: Y = A + B * X

Where Y is cumulative demand-related net additions to plant and x is cumulative additions to distribution level peak demand

A = -222.003
B = 0.203536

Marginal demand costs of distribution = $203.54

(a) from study workpapers
(b) from study workpapers
(c) a - b
(d) from study workpapers
(e) from study workpapers
(f) c + d + e
(g) Handy Whitman Index
(h) f * g
(i) cumulative h
(j) cumulative peak Load additions in study workpapers

The functional subtraction method, in which it is possible to remove all non-demand related costs including the minimum grid, provides the most straightforward calculation. An analyst who employs the engineering method would have to determine individually for each facility which portion of the facility or the investment was incurred to serve customers and what proportion was incurred to serve demand. In both cases, the capacity costs are annualized and adjusted for operation and maintenance costs and for indirect costs. Absent special operation and maintenance studies, it is reasonable to divide O&M costs between customer and demand components on the assumption that they are proportional to the split in the distribution investment. Again, as in the transmission calculation, further adjustments can also be made to account for the losses and the energy component of the distribution cost using the methods outlined above. See Table 10-4.

TABLE 10-4
Demand Related Marginal Cost of Distribution
Minimum Grid vs. Customer Specific Equipment Methodologies
(1988 $)

Description	Minimum Grid $ per KW	Customer Specific Equipment $ per KW
Distribution Investment per KW change in Load (From Tables 10-3A & 10-3B)	159.13	203.54
Annual Cost (*13.08%)	20.82	26.62
Demand Related O&M Expense	5.69	9.17
General Plant Loading	0.80	1.02
Working Capital	0.37	0.47
Total Annual Costs of Distribution/KW	27.67	37.28
Loss Adjustment (1.107%)	30.63	41.27

B. Non-Coincident Peak Demand

To calculate the marginal demand related distribution cost for a particular customer class, the analyst needs to determine, using available load data, the increase in peak demand on the distribution system due to a 1 KW increase in the maximum demand of the class. The peak demand on the distribution system is referred to as the non-coincident peak demand.

Unfortunately, most load research studies have tended to focus on the structure of class demands at the generation and at the customer levels and, therefore, very little is known about the demands on the mid-stream components of the transmission and distribution systems. Consequently, analysts have resorted to various simplifying assumptions in order to determine transmission and distribution system non-coincident peaks. For power systems which depend for the most part on their own resources, it is often assumed that the class composition of the transmission system non-coincident peak demand is identical to the composition of the coincident peak demand at the generation level. This assumption may need to be amended for power systems with important interconnections with other systems.

Unlike the transmission system, however, secondary distribution systems are designed to meet load growth in particular localities. This means, of course, that the non-coincident peak on any portion of the secondary system reflects the combined load of the customers served from it. Because of zoning and land use regulations, load on any particular portion of the secondary system will generally be dominated by either residential or commercial customers. (Industrial customers are more likely to be served directly from the primary distribution system.) This suggests that a close relationship exists between an increase in the maximum demand of the residential or commercial class and the increase in the secondary non-coincident peak (i.e., coincident factor close to unity) for any particular locality. Where customer classes served from the secondary distribution system are mixed this result needs to be amended to take account of the diversity between the classes. As the residential class far out-numbers the commercial class on most systems, the secondary distribution system as a whole will be primarily responsive to residential loads.

Logically, the class demand at the time of peak on the primary distribution system must lie between the previously determined transmission and secondary distribution class demands and it is common to take the statistical average of the two demands.

C. Allocation of Costs to Time Periods

Most analysts assume that the customer related marginal distribution costs do not vary by season or by time of day.

The method adopted to attribute marginal demand related distribution costs depends on the load characteristics of the distribution network. When distribution system components experience maximum demand during the peak costing period identified in the generation analysis, the allocation methods employed for generation (uniform allocation across peak period, probability of excess demand, loss of load probability), and sometimes simply the generation allocation factors themselves, can be used to attribute distribution costs to time periods. As noted above in the discussion on the allocation of transmission costs, if the generation allocators are used it may be necessary to adjust for the effect of the ambient temperature on line capacity and, therefore, on the seasonal allocation of costs. Load research at the distribution substation transformer level has indicated in a number of jurisdictions, however, that different segments of the distribution network peak at different times in the day and year, and are not closely related to the system peak. Those jurisdictions may find it more appropriate to adopt an equal allocation of distribution capacity costs or to allocate costs based on either the proportions of the number of substations that peak during the individual costing periods, or by relating the amount of distribution investment to the timing of the peak demand where the investment was made.

III. CUSTOMER

Marginal customer costs in the functionalization step of a marginal cost of service study are generally identified as those facilities and services that are specific to individual customers. These costs include the costs of the service drops, the costs of meters and metering and the customer accounts expenses. These costs are assumed to vary solely according to the number of customers on the utility's system, and are, therefore, classified 100 percent customer related as well. Jointly used facilities such as line transformers and interconnecting secondary conductors that have been functionalized as distribution costs and that the analyst may have classified as customer related, have been discussed above in the "Distribution" section.

A. Costing Methodologies

Most analysts assume that in current dollars there is little incremental change in the cost of customer related facilities and expenses. Since customer related facilities are added in small increments and exhibit little technological change, the effects of vintaging and technological change, which normally distinguish marginal and embedded costs, are reduced. Thus, while it would be possible to calculate over some planning horizon the change in customer related cost in constant dollars against the expected change in the number of customers, the analyst would not expect the resulting marginal cost to differ significantly from the average embedded cost. Therefore, most marginal cost studies adopt a form of embedded analysis to calculate the total investment cost which is then amortized using an economic carrying charge.

If the minimum grid methodology is used, the customer related investment cost is that calculated in the distribution portion of the study. Otherwise, the cost of meters and service drop investment is analyzed separately by the type of metering installation or by customer load class by determining the characteristics of the service required. While it would be possible to identify separate demand and customer components of meter costs assuming that the more complex metering can be identified with higher levels of demand, all metering costs are usually charged on a per customer basis and, therefore, there is no reason to distinguish between the two components. Annual costs of each type of equipment are calculated by multiplying the installed cost by an annual carrying charge, and adding a factor to reflect operation and maintenance expenses.

Customer accounts (meter reading and billing), service and informational expenses are usually analyzed over a recent historical period, with the expenses converted to current year dollars. The customers in each customer class are weighted based on an embedded study of costs per customer or on discussions with company personnel. The customer expenses are allocated to each load class based on the weighted number of customers. See Tables 10-5A and 10-5B.

B. Allocation of Costs to Time Periods

While a case could be made that there are seasonal variations to such customer accounts as meter reading and customer information, the data is typically not analyzed on a monthly basis and there is no attempt at seasonal differentiation in the cost studies.

Table 10-5A
Customer Related Marginal Costs - Minimum

	Residential	GS-1	Commercial GS-P	GS2-S	Sub-T	Industrial Primary	Sec	Agricultural
Customer Related Investment Cost	759.00	755.00	2723.00	2416.00	8290.00	8701.00	20262.00	1763.00
Annualized Cost	99.28	98.75	356.17	316.01	1084.33	1138.09	2650.27	230.60
Customer related O&M	17.00	17.00	62.00	55.00	189.00	198.00	462.00	40.00
General Plant Loading	3.82	3.80	13.71	12.17	41.75	43.82	102.04	8.88
Working Capital	1.69	1.68	6.05	5.37	18.43	19.35	45.05	3.92
Customer Account Expenses	26.00	42.00	42.00	42.00	886.00	886.00	886.00	79.00
Total Customer Marginal Cost	147.79	163.23	479.93	430.55	2219.51	2285.26	4145.36	362.40
Weighted Average	147.79		224.61			3599.08		362.40

Table 10-5B
Customer Related Marginal Costs - Customer Specific

	Residential	GS-1	Commercial GS-2	GS2-S	Sub-T	Industrial Primary	Sec	Agricultural
Customer Related Investment Cost	309.09	476.37	2007.83	5209.66	8473.46	8473.46	14716.85	2861.61
Annualized Cost	40.43	962.31	262.62	681.42	1108.33	1108.33	1924.96	374.30
Customer Related O&M-Same % as MG	6.92	10.73	45.72	118.60	193.18	192.82	335.56	64.93
Customer Install Equipment	0.46	0.47	1.68	1.49	9.43	5.45	12.54	1.09
General Plant Loading	1.56	2.40	10.11	26.23	42.67	42.67	74.11	14.41
Working Capital	0.69	1.06	4.46	11.58	18.84	18.84	32.72	6.36
Customer Account Expenses	26.00	42.00	42.00	42.00	886.00	886.00	886.00	79.00
Total Customer Marginal Cost	76.05	118.97	366.60	881.33	2258.43	2254.11	3265.90	540.09
Weighted Average Class MC	76.05		285.75			2970.31		540.09

APPENDIX C

1997 MARGINAL COST STUDY

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1997 MARGINAL COST STUDY

1.0 Introduction

In Order No. P.U. 7 (1996-1997), the Board ordered Newfoundland Power to conduct a study to evaluate rate designs based upon marginal cost, time-of-use design principles and other innovative rate options. This Appendix describes in detail the calculation of marginal costs for the study.

The calculation of marginal costs for an electric utility is complex. The methods are well described in the NARUC *Electric Utility Cost Allocation Manual* (January, 1992, Section III). In general, we have followed the methods described in the NARUC cost allocation manual except for distribution costs. An excerpt from the NARUC manual is attached as Appendix B of the study. The method used for distribution is based on a recent marginal cost methodology put forward by the National Energy Research Associates ("NERA") and described in Section 7.1.

2.0 Marginal Cost for the Island Interconnected System.

The marginal costs are summarized in Table 1, which shows the estimated system marginal energy, demand, and customer costs for the years 1997 through 2005. We have assumed that the marginal cost for Newfoundland Power is the sum of Newfoundland Power's marginal costs and the marginal costs on the portion of Newfoundland and Labrador Hydro's ("Hydro's") system that is required to service Newfoundland Power. The details of the calculation of each component of the marginal cost is discussed in the following sections.

Table 1

Island Interconnected System
Newfoundland Power's Marginal Costs

	Short Run Marginal Energy Cost		Long-Run Marginal Demand Cost On-Peak					Long-Run Marginal
Year	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Generation Capacity ($/kW-yr)[1]	Hydro Transmission ($/kW-yr)	NP Transmission ($/kW-yr)	Distribution Primary $/kW-yr)	Distribution Secondary ($/kW-yr)	Customer Cost ($/Weighted Cust)
1997	4.24	4.03	N/A	14.1	1.1	2.4	2.0	330
1998	4.25	4.04	N/A	14.4	1.1	2.4	2.0	336
1999	4.32	4.11	N/A	14.6	1.1	2.5	2.0	342
2000	4.47	4.25	N/A	15.0	1.1	2.5	2.1	350
2001	4.62	4.39	90.2	15.3	3.2	6.5	2.1	358
2002	4.20	3.99	92.5	15.7	3.3	6.7	2.2	366
2003	4.38	4.16	94.8	16.1	3.3	7.9	2.3	375
2004	4.62	4.39	97.2	16.5	3.4	7.0	2.3	384
2005	4.84	4.60	99.8	16.9	3.5	7.2	2.4	394

3.0 Difficulties Determining the Marginal Cost

3.1 Difficulties Determining the Marginal Generation Cost

Newfoundland Power currently purchases most of its power from Hydro. Therefore we must rely on Hydro to supply most of the data on the marginal costs of the generation system. Since Hydro was unable to participate in this study, their production costing model and system expansion plans could not be used.

[1] N/A - Not Available.

Without expansion plan analysis, the most acceptable means to calculate marginal capacity costs is the peaker deferral method. Newfoundland Power used an estimate of capital and operating costs for future combustion turbines provided by Hydro.

Without production costing analysis, estimating future short run marginal costs is more difficult. Fortunately, the current generation system in Newfoundland is relatively simple. The Island Interconnected System in Newfoundland consists of numerous hydraulic generating facilities, Hydro's Holyrood thermal generating plant ("Holyrood") and a number of combustion turbine and diesel generators. To meet the system's energy requirements, existing hydraulic generation plants are fully utilized, with Holyrood making up the remaining load requirements. Peaking units (i.e., combustion turbines and diesel plants) are only used when forced outages limit the availability of other plants. Modelling this simple arrangement can be done without production costing software. We modeled Holyrood as the marginal generation for all times during the year, except when a forced outage requires a combustion turbine to operate. (See Section 4.0).

Recent forecasts indicate the need for additional generation as early as the year 2001, even without the additional load of the Voisey Bay Nickel smelter/refinery. Depending on how the system expands and what new units are added, the method used in this study will become less exact. If large amounts of independent power become available, calculating the avoided generation costs will become more difficult because the characteristics of independent power are often unique to the supplier, and independent power is often cheaper than conventional alternatives.

We expect that the marginal generation capacity costs obtained in this study will err on the high side, because they do not properly account for the large amounts of independent power that may become available. In addition, Hydro is currently looking at its own options, which may be cost less than combustion turbines when fuel savings are taken into account.

3.2 Difficulties Determining the Marginal Transmission and Distribution Cost

Without Hydro's direct participation, the estimation of the future costs of Hydro's transmission system is difficult. To assist in the development of marginal costs for Hydro's transmission system, Hydro provided historic costs which were used to determine historical marginal costs. We assumed the historical marginal costs will apply in the future.

There were also difficulties in assessing the marginal costs of Newfoundland Power's transmission and distribution system. The problem arises because the growth in demand has decreased rapidly in the last five to ten years, and spare capacity has built up in the system. We had originally hoped to use both historical and budget data to predict future marginal costs. However, analysis of the historical data resulted in marginal costs that are not comparable to the marginal cost derived from the current five year budget. The use of the historical numbers would have severely overstated the long-run marginal costs of demand on the transmission system between now and the year 2005. (See Schedule 1). As a result, we have limited our analysis to the four year projection in capital additions contained in the Company's capital budget forecast. The results reveal that the marginal costs of transmission and distribution are expected to be quite low during the next four years. Beyond the next four years, a review of long range plans indicates only a slight increase in marginal costs. Therefore, given current growth trends projected load over the next ten years can be accommodated at relatively low cost.

Most of the difficulties associated with calculating marginal costs for the Island Interconnected System are related to estimates of long-run marginal costs beyond the turn of the century. We feel that any reflection in rates of long-run marginal costs beyond the year 2000 should be approached with caution.

4.0 Marginal Generation Cost

There are three components to the marginal generating costs shown in Table 1: the short run marginal energy cost on-peak, the short-run marginal energy cost off-peak, and the long-run marginal demand cost on-peak. The long-run marginal demand cost off-peak is assumed to be zero.

The marginal cost of off-peak energy was taken to be Holyrood's operating costs since Holyrood is on the margin almost all hours of the year, except when gas turbines are operating. There is a significantly greater chance that gas turbines will operate during on-peak periods. We have therefore assigned their costs to the on-peak period. Although gas turbines operate at less than a 1% capacity factor annually on the system, we have assumed that 5% of the on-peak hours will be served by gas turbines. The weighted on-peak energy cost has been increased to account for this.

The details of the marginal energy cost calculation are shown in Schedules 4 and 5 attached. They yield a 1997 short-run marginal energy cost of 4.03 cents/kWh off-peak and 4.24 cents/kWh on-peak. These values are escalated each year using a forecast of the GDP deflator for Canada and the forecast of oil prices to produce the projection in Table 1. Both of these forecasts were provided by the Conference Board of Canada and are shown in Schedule 21.

The on-peak long-run marginal generation demand-related costs shown in Table 1 have been calculated for the years in which a capacity shortfall is forecasted, which is currently estimated to be in 2001 and beyond. While capacity additions are not required for the years prior to 2001, there is clearly some value to capacity in those years, because there is always a possibility of losing load due to capacity being forced out of service. In the past, Newfoundland Power has used the National Energy Research Associates (NERA) probabilistic methods, which attempt to capture this effect. However, the Loss of Load Probability (LOLP) data used for its application has proven to be unstable. As a result, an estimate of the value of generation capacity for 1997 to 2000 is not available. To develop marginal cost-based rates, we need to assign a generation capacity cost for 1997. We have assumed that the value of generation capacity in 1997 is the full cost of deferring a gas turbine for a year ($83.1/kW in 1997 dollars).

The analysis ignores the effect of the Voisey Bay Nickel (VBN) smelter and refinery for the following reasons. First, we don't currently know what generation will be added to the system to serve the VBN load. Second, the Provincial Government has stated that VBN will be responsible for any incremental cost of serving their load, which means the addition of the VBN load should not materially affect the marginal costs.

5.0 Hydro's Marginal Transmission Cost

Hydro provides sufficient capacity in their transmission system to meet the requirements of Newfoundland Power. Hydro's transmission system has components common to all of their customers, and components specifically assigned to Newfoundland Power. The marginal cost of Hydro's transmission system is assigned to the on-peak period.

The total of the marginal cost estimates for these two components is shown in Table 1. The calculation of these marginal costs is shown in Schedule 6.

6.0 Newfoundland Power's Marginal Transmission Cost

The marginal cost of Newfoundland Power's transmission system, shown in Table 1, is composed of transmission line costs and a portion of substation costs. These components are built to meet peak demands and are classified as on-peak demand costs. These costs are based upon an analysis of the demand-related expenditures in the capital budgeting system for the next 4 years divided by the forecast increases in demand. Newfoundland Power has used a historical approach to these estimates in the past, but during the last 10 years load growth has dropped off significantly. This high growth in the past caused the transmission system to have surplus capacity for a considerable period into the future. The historical marginal transmission demand-related costs are therefore significantly higher ($3.9/kW-yr) than the forward-looking estimates ($0.3/kW-yr). (See Schedule 1). The projection of the costs in 2001 shows an increase in marginal costs as spare capacity within substations is utilized. (See Table 1).

The calculation of the marginal cost associated with transmission lines and substations is shown in Schedules 7 and 8 respectively. Approximately one third of the substation costs were allocated to the transmission system to obtain the total shown in Table 1 for 1997. Schedules 7 and 8 show the derivation of both the historical and forward-looking costs.

7.0 Newfoundland Power's Marginal Distribution Cost

The distribution system costs shown in Table 1 include both customer-related and demand-related marginal costs. Distribution costs are composed of substations, primary and secondary feeders, transformers, service drops, and meters and customer service costs. The costs in Table 1 for the primary system include the demand-related costs of the primary feeders, and approximately two thirds of the substation marginal costs. The marginal costs for the secondary system include the demand-related cost of the secondary feeders and the transformer costs. The estimates for each component must be done separately, since there are different percentages of each component associated with increases in number of customers versus increases in demand. The demand versus customer splits for each component are shown in Schedule 2.

There are two significant changes in the way Newfoundland Power has historically calculated distribution system marginal costs. The first change is in the percentage of costs assigned to the demand function. For purposes of the marginal cost study, the minimum distribution system study was not deemed to be appropriate. Instead a methodology used by the National Energy Research Associates ("NERA") based on the concept of a "facilities charge" was used. The methodology used in this study is described in Section 7.1.

The second significant change is the use of a forward-looking, rather than a historic, analysis of marginal distribution costs for the same reason cited in the discussion of Newfoundland Power's marginal transmission costs. Schedule 1 shows that marginal distribution system costs drop dramatically for the forward-looking method compared to the historic method. Because significant expenditures are not expected to be needed on the distribution system before 2005, we have used the new lower numbers. The primary demand-related costs shown in Table 1 for the year 2001 show an increase in marginal costs as spare capacity within substations is utilized.

The detailed calculations for the various distribution system costs are shown in Schedules 9 through 14.

7.1 Distribution Marginal Cost Methodology

The division of distribution costs between customer-, and demand-related classes has been much debated. It is generally conceded that services, meters, meter reading, and billing costs are customer-related (i.e., the costs vary directly with the number of customers in the system). As for the remaining distribution facilities, opinion is divided. As described in the NARUC manual excerpt, in Appendix B, the traditional approaches for determining the customer-related portion attempts to define some type of minimum system. In Newfoundland Power's embedded cost of service studies, the customer costs are estimated using a minimum system approach with the remainder of the distribution system classified as demand-related.

To deal with the demand/customer allocation issue on a marginal cost basis, the reasons for additions (as opposed to replacements) to the system must be examined. Three factors determine the additions required for the distribution system:

1. the number of new customers,
2 the design load of the new customers, and
3. the growth in peak demands which occur from year to year.

The addition of a customer requires a meter, a service drop and certain additional customer costs such as meter reading and billing. These costs are considered fixed costs and are not related to future changes in a customer's consumption. Consequently, these costs are allocated 100% to customer costs.

A new customer's design load determines the size of transformers, secondary feeders and primary extensions. Typically design loads are estimated conservatively, and provide for a certain degree of excess capacity. Variations in a customer's demand will require minimal changes to the capacity of transformers, secondaries and primary extensions. Therefore, most of the costs associated with transformers, secondaries and primary extensions are considered fixed, and not related to future changes in customer demand. These fixed costs give rise to a *facilities charge* that is related to the customers' design load.

If practical, marginal cost studies should incorporate this facilities charge. A lack of information on design loads and actual costs by customer type prevented us from developing a facilities charge related to design loads. Fixed costs should not be included with costs that vary with customer usage. Therefore, the fixed costs associated with design loads were combined with the fixed customer costs to produce an overall fixed customer cost component of the marginal cost.

We identified the costs associated with primary extensions, secondary feeders and transformer additions. A survey of Newfoundland Power's regional engineering staff indicated that 90% of these costs are related to new customers, and 10% are related to increases in the ongoing demand of existing customers. Therefore, we split the costs 10% to growth in the demands of existing customers, and 90% to new customers (and their design loads).

The change in demand on the distribution system from year to year gives rise to trunk feeder additions, (i.e., new feeders are added, conductor is upgraded to higher capacity), and occasionally upgrading of secondaries and transformers for capacity. These costs are considered variable demand costs and are allocated 100% to demand.

8.0 Marginal Costs Required For Rate Design

The rate designs in the study are based on current estimates of marginal cost. The marginal costs used for rate design are the 1997 costs shown in Table 1. As discussed in Section

2, the long-run marginal demand-related costs for generation are assumed to be $83.1 /kW in 1997 dollars. Before the marginal costs shown in Table 1 can be used for rate design, the costs must be adjusted to reflect the costs to service different types of customer, and increased to account for system losses.

Table 2 shows the marginal cost by type of customer. The losses built into these costs are shown in Schedule 15.

Table 2
Marginal Cost By Customer Type

Category		Secondary Customer	Primary Customer	Transmission Customer
Energy Cost				
On-Peak	(¢/kWh)	4.67	4.55	4.42
Off-Peak	(¢/kWh)	4.32	4.24	4.16
Winter	(¢/kWh)	4.55	4.45	4.33
Summer	(¢/kWh)	4.31	4.23	4.16
Demand Cost				
On-Peak	($/kW-yr)	115.5	110.0	103.2
Customer Cost				
Domestic	($/yr)	330	-	-
Rate 2.1	($/yr)	364	-	-
Rate 2.2	($/yr)	636	-	-
Rate 2.3	($/yr)	2,508	2,611	2,858
Rate 2.4	($/yr)	7,939	3,007	1,901

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

COMPARISON OF MARGINAL COST ESTIMATES BASED ON HISTORIC AND FUTURE COSTS

System Component	Long Run Marginal Demand Related Costs On-Peak		Short Run Marginal Energy Related Costs		Customer Related Marginal Costs	
	Future Costs $/kW	Historic Costs $/kW	On-Peak Costs cents/kWh	Off-Peak Costs cents/kWh	Future Costs $/WCUST	Historic Costs $/WCUST
Generation *	83.1	83.1	4.24	4.03		
Hydro Common						
Transmission	N/A	7.5				
Terminal Stations	N/A	3.5				
Hydro Specifically Assign						
Transmission	N/A	-				
Terminal Stations	N/A	3.2				
NP Transmission	0.3	3.9				
NP Substation	2.2	16.5				
NP Distribution						
Primary Feeders	0.9	20.8			46.2	45.4
Secondary Feeders	0.4	2.5			44.5	47.6
Transformers	1.6	2.5			114.6	92.2
Services					57.0	66.1
Meters *					10.3	10.3
NP Customer Related Expenses					N/A	57.5

N/A = Not Available
* - Marginal Costs are based on current cost estimates and are not based on either historic or future expenditures.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

ALLOCATION FACTORS

Primary/Secondary Functionalization Splits

Marginal Cost	Primary	Secondary	Source
Distribution Trunk Feeder Budget			
Demand Identified Items	100%	0%	Assumption
Customer Identified Items	80%	20%	Based on Embedded Rural Urban Split Analysis
Distribution Extension			
Marginal Investment	45%	55%	From Analysis of the Breakdown Codes for Distribution Extensions Capital Expenditures

Transmission/Distribution Functionalization Splits

	Transmission	Distribution	Source
Substation Costs	33.8%	66.2%	From Embedded Substation Plant Allocation

Demand/Customer Classification Splits

Marginal Cost	Demand	Customer	Source
Transmission	100%	0%	
Substations	100%	0%	
Distribution			
Trunk Feeder Growth Related Additions			Based on Itemized review of costs
Primary Extensions	10%	90%	Based on Survey of Engineering Staff
Secondary Extensions	10%	90%	Based on Survey of Engineering Staff
Transformers	10%	90%	Based on Survey of Engineering Staff
Services	0%	100%	
Meters	0%	100%	
Customer (Total O&M Costs)	0%	100%	

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1997 MARGINAL COST STUDY

2001 MARGINAL DEMAND RELATED COSTS ASSOCIATED WITH COMBUSTION TURBINES

Estimated Year of Next Generation Capacity Shortfall[1]		2001
ESTIMATED LONG RUN MARGINAL COSTS[2]		
- Marginal Investment per kW of System Peak (1997$) [3] (Includes A & G loading & Overheads)		$790 /kW
- Annualization factor related to capital investment		8.20%
- Annualized Costs[4]		$64.8 /kW
- Capacity Related O&M (1997$) [5]	9.97 $/kW	$10.0 /kW
- Total Capacity Costs related to Demand		$74.7 /kW
- Availability Factor[6]		89.97%
Long Run Marginal Demand Related Cost for Generation (1997$)		**$83.1 /kW**
Escalation to 2001		8.60%
LONG RUN MARGINAL GENERATION CAPACITY COST (2001$)		**$90.2 /kW**

NOTES:

1 - Based on latest forecast from Hydro that does not include VBN, January 1996.
2 - Applicable for years in which a capacity shortfall is identified.
3 - Based on an estimate from Hydro grossed up for escalation and IDC.
4 - Annualization Factor is developed on Schedule 17.
5 - Based on estimate from Hydro.
6 - Supplied by Hydro

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY
ON-PEAK SHORT RUN MARGINAL ENERGY COSTS

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

Fuel Costs

Fuel Forecast (A)	22.1 $/BBL[1]	
Holyrood Efficiency (B)	605 kWh/BBL[2]	
Marginal Fuel Cost (A/B*100)	3.65 cents/kWh	3.65 cents/kWh

Variable O&M

Marginal O&M[3]	0.38 cents/kWh	0.38 cents/kWh
Total Marginal Energy Costs Associated With Holyrood		**4.03 cents/kWh**

ESTIMATE OF MARGINAL ENERGY COSTS ASSOCIATED WITH GAS TURBINES

Fuel Costs

Fuel Forecast (A)	23.00 cents/l[4]	
Gas Turbine Efficiency (B)	3.00 kWh/l[5]	
Marginal Fuel Cost (A/B)	7.66 cents/kWh	7.66 cents/kWh

Variable O&M

Marginal O&M[6]	0.59 cents/kWh	0.59 cents/kWh
Total Marginal Energy Costs Associated With Gas Turbines		**8.25 cents/kWh**

WEIGHTED TOTAL MARGINAL ENERGY COSTS FOR THE ISLAND INTERCONNECTED SYSTEM

		Weightings	Weighted Totals
Marginal Holyrood Energy	4.03	95%	3.83 cents/kWh
Marginal Gas Turbine Energy	8.25	5%	0.41 cents/kWh
Total Weighted Marginal Energy Costs			**4.24 cents/kWh**

1 - Estimated price for residual oil purchased for Holyrood supplied by Conference Board of Canada (See Schedule 21). Actual costs have been fluctuating significantly.
2 - Supplied by Newfoundland Hydro.
3 - Supplied By Newfoundland Hydro.
4 - Estimated price for diesel fuel shown in Schedule 21.
5 - Supplied By Newfoundland Hydro.
6 - Estimated By Newfoundland Power.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

OFF-PEAK SHORT RUN MARGINAL ENERGY COSTS

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

Fuel Costs		
Fuel Forecast (A)	22.1 \$/BBL[1]	
Holyrood Efficiency (B)	605 kWh/BBL[2]	
Marginal Fuel Cost (A/B*100)	3.65 cents/kWh	3.65 cents/kWh
Variable O&M		
Marginal O&M[3]	0.38 cents/kWh	0.38 cents/kWh
Total Marginal Energy Costs Associated With Holyrood		**4.03 cents/kWh**

ESTIMATE OF MARGINAL ENERGY COSTS ASSOCIATED WITH GAS TURBINES

Fuel Costs		
Fuel Forecast (A)	23.00 cents/l[4]	
Gas Turbine Efficiency (B)	3.00 kWh/l[5]	
Marginal Fuel Cost (A/B)	7.66 cents/kWh	7.66 cents/kWh
Variable O&M		
Marginal O&M[6]	0.59 cents/kWh	0.59 cents/kWh
Total Marginal Energy Costs Associated With Gas Turbines		**8.25 cents/kWh**

WEIGHTED TOTAL MARGINAL ENERGY COSTS FOR THE ISLAND INTERCONNECTED SYSTEM

		Weightings	Weighted Totals
Marginal Holyrood Energy	4.03	100%	4.03 cents/kWh
Marginal Gas Turbine Energy	8.25	0%	- cents/kWh
Total Weighted Marginal Energy Costs			**4.03 cents/kWh**

1 - Estimated price for residual oil purchased for Holyrood supplied by Conference Board of Canada (See Schedule 21). Actual costs have been fluctuating significantly.
2 - Supplied by Newfoundland Hydro.
3 - Supplied By Newfoundland Hydro.
4 - Estimated price for diesel fuel shown in Schedule 21.
5 - Supplied By Newfoundland Hydro.
6 - Estimated By Newfoundland Power.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

MARGINAL COSTS FOR NLH's COMMON TRANSMISSION SYSTEM
Based on Historical Costs (All Costs X $1,000)

	Marginal Transmission Investments			Marginal Terminal Station Investments			NLH	
Year	Growth Investments Current$[1]	Escalation to 1997[2]	Growth Investments 1997$	Growth Investments Current$[1]	Escalation to 1997	Growth Investments 1997$	System Peak Demand MW[3]	Increase In Peak Load MW
1986							1,204	
1987	-	1.327	-	1,750	1.299	2,274	1,308	104
1988	-	1.215	-	-	1.207	-	1,435	127
1989	-	1.174	-	-	1.119	-	1,500	65
1990	13,867	1.144	15,860	551	1.111	612	1,488	(12)
1991	-	1.169	-	-	1.160	-	1,458	(30)
1992	-	1.183	-	3,822	1.159	4,430	1,452	(6)
1993	-	1.152	-	-	1.153	-	1,480	28
1994	-	1.092	-	-	1.078	-	1,429	(51)
1995	-	1.034	-	-	1.034	-	1,563	134
1996	-	1.026	-	-	1.026	-	1,445	(118)
TOTALS			15,860			7,317	Growth Trend	19.4

MARGINAL COST OF DEMAND ON NLH's COMMON SYSTEM

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

Total Growth Investments (1987 to 1996) (1997$):	$15,860 (X $1,000)	
Growth (for ten years)	194 MW	
Marginal Investment	82 $/kW	
Annualization Factor[4]	7.12%	
Marginal Demand Cost	**5.83 $/kW**	**5.83 $/kW**

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

Marginal Investment (1997$)	82 $/kW	
O&M Percentage[5]	2.00%	
Marginal Demand Cost	**1.64 $/kW**	**1.64 $/kW**

Subtotal for Common Transmission Lines **7.46 $/kW**

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

Total Growth Investments (1987 to 1996) (1997$):	$7,317 (X $1,000)	
Growth (for ten years)	194 MW	
Marginal Investment	38 $/kW	
Annualization Factor[4]	7.20%	
Marginal Demand Cost	**2.72 $/kW**	**2.72 $/kW**

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

Marginal Investment (1997$)	38 $/kW	
O&M Percentage	2.00%	
Marginal Demand Cost	**0.76 $/kW**	**0.76 $/kW**

Subtotal for Common Terminal Stations **3.47 $/kW**

TOTAL MARGINAL COSTS ASSOCIATED WITH NLH's COMMON SYSTEM **10.94 $/kW**

NOTES:
1 - The capital expenditures related to growth were supplied by NLH.
2 - Escalation Index taken from Statistics Canada Utility Construction Price Indices.
3 - Actual Peaks, Growth Trend is based on regression analysis of actual peaks. It is used to estimated the growth implied in the peak demands.
4 - Annualization Factor derived on Schedule 17.
5 - O&M Estimated at 2% of Investment.

MARGINAL COSTS FOR NLH's SYSTEM THAT IS SPECIFICALLY ASSIGNED TO NP

Based on Historical Costs (All Costs X $1,000)

	Marginal Transmission Investments			Marginal Terminal Station Investments				
Year	Growth Investments Current$[1]	Escalation to 1997[2]	Growth Investments 1997$	Growth Investments Current$[1]	Escalation to 1997[2]	Growth Investments 1997$	NP System Peak Demand MW[3]	Increase In Peak Load MW
1986							863	
1987	-	1.327	-	-	1.299	-	890	27
1988	-	1.215	-	2,144	1.207	2,588	969	79
1989	-	1.174	-	2,640	1.119	2,954	1,106	137
1990	-	1.144	-	1,049	1.111	1,165	1,073	(33)
1991	-	1.169	-	-	1.160	-	1,100	27
1992	-	1.183	-	-	1.159	-	1,027	(73)
1993	-	1.152	-	-	1.153	-	1,098	71
1994	-	1.092	-	-	1.078	-	1,031	(67)
1995	-	1.034	-	-	1.034	-	1,123	92
1996	-	1.026	-	-	1.026	-	1,081	(42)
TOTALS			-			6,708	Growth Trend	19.5

MARGINAL COST OF DEMAND ON NLH's COMMON SYSTEM

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

Total Growth Investments (1987 to 1996) (1997$):	$0 (X $1,000)	
Growth (for ten years)	195 MW	
Marginal Investment	- $/kW	
Annualization Factor[4]	7.12%	
Marginal Demand Cost	**0.0 $/kW**	**0.0 $/kW**

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

Marginal Investment (1997$)	- $/kW	
O&M Percentage[5]	2.00%	
Marginal Demand Cost	**0.0 $/kW**	**0.0 $/kW**

Subtotal for Specifically Assigned Transmission Lines **0.0 $/kW**

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

Total Growth Investments (1987 to 1996) (1997$):	$6,708 (X $1,000)	
Growth (for ten years)	195 MW	
Marginal Investment	34 $/kW	
Annualization Factor[4]	7.20%	
Marginal Demand Cost	**2.5 $/kW**	**2.5 $/kW**

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

Marginal Investment (1997$)	34 $/kW	
O&M Percentage	2.00%	
Marginal Demand Cost	**0.7 $/kW**	**0.7 $/kW**

Subtotal for Specifically Assigned Terminal Stations **3.2 $/kW**

TOTAL MARGINAL COSTS ASSOCIATED WITH NLH's COMMON SYSTEM **3.2 $/kW**

NOTES:

1 - The capital expenditures related to growth were supplied by NLH.
2 - Escalation Index taken from Statistics Canada Utility Construction Price Indices.
3 - Actual Peaks, Growth Trend is based on regression analysis of actual peaks. It is used to estimated the growth implied in the peak demands.
4 - Annualization Factor derived on Schedule 17.
5 - O&M Estimated at 2% of Investment.

MARGINAL COSTS FOR NP's TRANSMISSION SYSTEM
Based on Future Costs (All Costs X $1,000)

Year	Marginal Transmission Investments: Total Growth Investments[1] Current$	Escalation[2] to 1997	Total Growth Investments 1997$	NP System Peak Demand[3] MW	Increase In Peak Load MW
FORECAST					
1996				1,067.6	
1997	240	1.000	240	1,086.0	18.4
1998	-	0.990	-	1,100.3	14.3
1999	-	0.980	-	1,119.1	18.8
2000	-	0.971	-	1,136.9	17.8
TOTALS			240	Growth Trend	17.2

MARGINAL COST OF NP's TRANSMISSION LINES

a	Total Growth Investments 1987 to 1996 (1997$)	240	(X $1,000)
b	Growth (For 10 Years)	69	MW
c	Marginal Investment	3.49	$/kW
d	Increm. Capitalized Gen. Expense (c X 9.6%)	0.28	$/kW
e	General Plant Loading (c X 12.5%)	0.44	$/kW
f	**Total Marginal Investment Cost**	**4.21**	**$/kW**
g	Annualization Factor	6.81%	
h	Plant Related Gen. Exp. Loading	0.27%	
	Annualized Cost of Capital Additions	**0.30**	**$/kW**
i	Marginal O&M Expense ((c+d) X 0.7%)	0.03	$/kW
j	A & G Expense Loading Factor	1.30	
k	**Total Demand Related O&M Expense**	**0.03**	**$/kW**
	Working Capital		
l	Materials and Supplies (f X 0.46%)	0.02	
m	Prepayments (f X 0.28%)	0.01	
n	Cash Working Capital Allow. (k X 1.7%)	0.00	
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%)	0.00	
p	**Total Demand Related Working Capital**	**0.00**	**$/kW**

TOTAL MARGINAL COSTS ASSOCIATED WITH TRANSMISSION **0.34 $/kW**

NOTES:

1 - From a review of the five year capital forecast, November 1996.
2 - Escalation based on 0% labour escalations and 2% material escalation for an average of 1.0%.
3 - Taken from the Energy Supply Forecast, October 1996.

MARGINAL COSTS FOR NP's TRANSMISSION SYSTEM
Based on Historical Costs (All Costs X $1,000)

	Marginal Transmission Investments			NP	
Year	Total Growth Investments[1] Current$	Escalation[2] to 1997	Total Growth Investments 1997$	System Peak Demand[3] MW	Increase In Peak Load MW
HISTORIC					
1986				863	
1987	-	1.327	-	890	
1988	456	1.215	554	969	79
1989	931	1.174	1,092	1,106	137
1990	1,002	1.144	1,146	1,073	(33)
1991	932	1.169	1,090	1,100	27
1992	1,101	1.183	1,303	1,027	(73)
1993	750	1.152	864	1,098	71
1994	161	1.092	176	1,031	(67)
1995	479	1.034	495	1,123	92
1996	-	1.026	-	1,081	(42)
TOTALS			6,224	Growth Trend	19.5

MARGINAL COST OF NP's TRANSMISSION LINES

a	Total Growth Investments 1987 to 1996 (1997$)	$6,224	(X $1,000)
b	Growth (For 10 Years)	195	MW
c	Marginal Investment	31.9	$/kW
d	Increm. Capitalized Gen. Expense (c X 9.6%)	3.1	$/kW
e	General Plant Loading (c X 12.5%)	4.0	$/kW
f	**Total Marginal Investment Cost**	39.0	
g	Annualization Factor	8.71%	
h	Plant Related Gen. Exp. Loading	0.27%	
	Annualized Cost of Capital Additions	**3.5**	**$/kW**
i	Marginal O&M Expense ((c+d) X 0.7%)	0.2	$/kW
j	A & G Expense Loading Factor	1.30	
k	**Total Demand Related O&M Expense**	**0.3**	**$/kW**
	Working Capital		
l	Materials and Supplies (f X 0.46%)	0.18	
m	Prepayments (f X 0.28%)	0.11	
n	Cash Working Capital Allow. (k X 1.7%)	0.01	
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%)	0.04	
p	**Total Demand Related Working Capital**	**0.04**	**$/kW**

TOTAL MARGINAL COSTS ASSOCIATED WITH TRANSMISSION **3.9 $/kW**

NOTES:

1 - From Detailed Work Order Review.
2 - Escalation Index taken from Statistics Canada's Utility Construction Price Indices.
3 - Actual Historical Peak Demand for Newfoundland Power.

MARGINAL COSTS FOR NP's SUBSTATIONS
Based on Future Costs (All Costs X $1,000)

Year	Marginal Substation Investments: Total Growth Investments[1] Current$	Escalation[2] to 1997	Total Growth Investments 1997$	NP System Peak Demand[3] MW	Increase In Peak Load MW
FORECAST				1,067.6	
1997	122	1.00	122	1,086.0	18.4
1998	138	0.99	137	1,100.3	14.3
1999	-	0.98	-	1,119.1	18.8
2000	887	0.97	861	1,136.9	17.8
TOTALS			1,120	Growth Trend	17.2

MARGINAL COST OF SUBSTATIONS

a	Growth Investments (1997$)	1,120	(X $1,000)
b	Growth (For 4 Years)	69	MW
c	Marginal Investment	16.32	$/kW
d	Increm. Capitalized Gen. Expense (c X 9.6%)	1.31	$/kW
e	General Plant Loading (c X 12.5%)	2.04	$/kW
f	**Total Marginal Investment Cost**	**19.67**	
g	Annualization Factor	8.71%	
h	Plant Related Gen. Exp. Loading	0.27%	
	Annualized Cost of Capital Additions	**1.8**	**$/kW**
i	Marginal O&M Expense ((c+d) X 1.76%)	0.31	$/kW
j	A & G Expense Loading Factor	1.30	
k	**Total Demand Related O&M Expense**	**0.40**	**$/kW**
	Working Capital		
l	Materials and Supplies (f X 0.46%)	0.09	
m	Prepayments (f X 0.28%)	0.06	
n	Cash Working Capital Allow. (k O&M X 1.7%)	0.01	
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%)	0.02	
p	**Total Demand Related Working Capital**	**0.02**	**$/kW**

TOTAL MARGINAL COSTS ASSOCIATED WITH SUBSTATIONS **2.19 $/kW**

NOTES:

1 - From a review of the Five Year Capital Forecast, November 1996.
2 - Escalation based on 0% Labour Escalations and 2% Material Escalation for an average of 1.0%.
3 - Taken from the Energy Supply Forecast, October 1996.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

MARGINAL COSTS FOR NP's SUBSTATIONS

Based on Historical Costs (All Costs X $1,000)

Year	Marginal Substation Investments: Total Growth Investments[1] Current$	Escalation[2] to 1997	Total Growth Investments 1997$	NP System Peak Demand[3] MW	Increase In Peak Load MW
1986		1.397	-	863	
1987	858	1.299	1,115	890	27
1988	1,413	1.207	1,706	969	79
1989	1,019	1.119	1,141	1,106	137
1990	6,592	1.111	7,325	1,073	(33)
1991	3,367	1.160	3,906	1,100	27
1992	2,641	1.159	3,062	1,027	(73)
1993	1,965	1.153	2,266	1,098	71
1994	323	1.078	348	1,031	(67)
1995	52	1.034	53	1,123	92
1996	91	1.026	94	1,081	(42)
TOTALS			21,016	Growth Trend	19.5

MARGINAL COST OF SUBSTATIONS

a	Growth Investments (1997$)	$21,016	(X $1,000)
b	Growth (For 10 Years)	195	MW
c	Marginal Investment	107.7	$/kW
d	Increm. Capitalized Gen. Expense (c X 9.6%)	10.3	$/kW
e	General Plant Loading (c X 12.5%)	13.5	$/kW
f	**Total Marginal Investment Cost**	131.5	
g	Annualization Factor	9.09%	
h	Plant Related Gen. Exp. Loading	0.27%	
	Annualized Cost of Capital Additions	**12.3**	**$/kW**
i	Marginal O&M Expense ((c+d) X 1.76%)	2.1	$/kW
j	A & G Expense Loading Factor	1.30	
k	**Total Demand Related O&M Expense**	**4.07**	**$/kW**
	Working Capital		
l	Materials and Supplies (f X 0.46%)	0.61	
m	Prepayments (f X 0.28%)	0.37	
n	Cash Working Capital Allow. (k X 1.7%)	0.07	
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%)	0.14	
	Total Demand Related Working Capital	**0.14**	**$/kW**
	TOTAL MARGINAL COSTS ASSOCIATED WITH SUBSTATIONS	**16.5**	**$/kW**

NOTES:

1 - From Detailed Work Order Review.
2 - Escalation Index taken from Statistics Canada's Utility Construction Price Indices.
3 - Actual Historical Peak Demand for Newfoundland Power.

MARGINAL COSTS ASSOCIATED WITH PRIMARY
Based on Future Costs (All Costs X $1,000)

Year	Total Primary Investment[1] Current$	Investment Allocated to Demand Growth Current$	Escalation to 1997[2]	Investment Allocated to Demand Growth 1997$	NP Peak Demand[3] MW	Increase in Peak[4] MW	Investment Allocated to Customer Growth Current$	Escalation to 1997[2]	Investment Allocated to Customer Growth 1997$	Average Weighted Customers[5] WCUST	Increase In Customers WCUST
1996					1,068					198,494	
1997	$897	$161	1.000	$161	1,086	18	$736	1.000	736	200,113	1,619
1998	$882	$181	0.990	$179	1,100	14	$701	0.990	694	201,927	1,814
1999	$646	$164	0.980	$160	1,119	19	$483	0.980	473	203,821	1,894
2000	$976	$477	0.971	$463	1,137	18	$498	0.971	484	205,904	2,083
TOTALS				$501	Growth trend	17.2			1,903		5,327

MARGINAL COSTS ASSOCIATED WITH NP'S DISTRIBUTION PRIMARY

		Demand Related		Customer Related	
a	Growth Investments (1997$)	501	(X $1,000)	1,903	(X $1,000)
b	Growth (For 4 Years)	69	MW	5,327	WCUST
c	Marginal Investment	7.29	$/kW	357	$/WCUST
d	Increm. Capitalized Gen. Expense (c X 9.6%)	0.58	$/kW	28.6	$/WCUST
e	General Plant Loading (c X 12.5%)	0.91	$/kW	44.7	$/WCUST
f	**Total Marginal Investment Cost**	**8.79**	**$/kW**	**430.4**	**$/WCUST**
g	Annualization Factor	9.09%		9.09%	
h	Plant Related Gen. Exp. Loading	0.27%		0.27%	
	Annualized Cost of Capital Additions	**0.82**	**$/kW**	**40.3**	**$/WCUST**
i	Marginal O&M Expense ((c+d) X 1.09%)	0.09	$/kW	4.2	$/WCUST
j	A & G Expense Loading Factor	1.30		1.30	
k	**Total Marginal O&M Expense**	**0.11**	**$/kW**	**5.5**	**$/WCUST**
	Working Capital				
l	Materials and Supplies (f X 0.46%)	0.04	$/kW	1.98	$/WCUST
m	Prepayments (f X 0.28%)	0.02	$/kW	1.21	$/WCUST
n	Cash Working Capital Allow. (k X 1.7%)	0.00	$/kW	0.09	$/WCUST
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%)	0.01	$/kW	0.43	$/WCUST
p	**Total Marginal Working Capital**	**0.01**	**$/kW**	**0.4**	**$/WCUST**
	TOTAL MARGINAL COST	**0.94**	**$/kW**	**46.2**	**$/WCUST**

Notes: 1 - Total Primary Investment and allocation between Demand and Customer is determined in Schedule 16.
2 - Escalation based on 0% Labour Escalations and 2% Material Escalation for an average of 1.0%.
3 - Taken from the Energy Supply Forecast, October 1996.
4 - A simple linear regression is used to determine the growth trend within the peak demands.
5 - Weighted Customers based on forecast of customers and the weighting factors shown in Schedule 22.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

MARGINAL COSTS ASSOCIATED WITH PRIMARY
Based on Historical Costs (All Costs X $1,000)

Year	Total Primary Investment[1] Current$	Investment Allocated to Demand Growth Current$	Escalation to 1997[2]	Investment Allocated to Demand Growth 1997$	NP Peak Demand[3] MW	Increase in Peak MW	Investment Allocated to Customer Growth Current$	Escalation to 1997[2]	Investment Allocated to Customer Growth 1997$	Average Weighted Customers[4] WCUST	Increase In Customers WCUST
1991					1,100					185.461	
1992	$2,289	$1,256	1.152	$1,447	1,027	(73)	$1,033	1.152	1,190	188.746	3.285
1993	$1,659	$686	1.124	$771	1,098	71	$974	1.124	1,094	191.626	2.880
1994	$1,335	$583	1.087	$634	1,031	(67)	$751	1.087	817	194.417	2.791
1995	$538	$152	1.034	$158	1,123	92	$386	1.034	399	196.691	2.274
1996	$780	$157	1.026	$161	1,081	(42)	$623	1.026	639	198.494	1.804
TOTALS				$2,852	Growth trend	3.6			3.101		8.956

MARGINAL COSTS ASSOCIATED WITH NP'S DISTRIBUTION PRIMARY

		Demand Related		Customer Related	
a	Growth Investments (1997$)	2,852	(X $1,000)	3,101	(X $1,000)
b	Growth (For 5 Years)	18	MW	8,956	WCUST
c	Marginal Investment	159	$/kW	346	$/WCUST
d	Increm. Capitalized Gen. Expense (c X 9.6%)	15.2	$/kW	33.2	$/WCUST
e	General Plant Loading (c X 12.5%)	19.8	$/kW	43.3	$/WCUST
f	**Total Marginal Investment Cost**	**193.6**	**$/kW**	**422.8**	**$/WCUST**
g	Annualization Factor	9.09%		9.09%	
h	Plant Related Gen. Exp. Loading	0.27%		0.27%	
	Annualized Cost of Capital Additions	**18.1**	**$/kW**	**39.6**	**$/WCUST**
i	Marginal O&M Expense ((c+d) X 1.09%)	1.9	$/kW	4.1	$/WCUST
j	A & G Expense Loading Factor	1.30		1.30	
k	**Total Marginal O&M Expense**	**2.5**	**$/kW**	**5.4**	**$/WCUST**
	Working Capital				
l	Materials and Supplies (f X 0.46%)	0.89	$/kW	1.94	$/WCUST
m	Prepayments (f X 0.28%)	0.54	$/kW	1.18	$/WCUST
n	Cash Working Capital Allow. (k X 1.7%)	0.04	$/kW	0.09	$/WCUST
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%)	0.19	$/kW	0.42	$/WCUST
	Total Marginal Working Capital	**0.2**	**$/kW**	**0.4**	**$/WCUST**
	TOTAL MARGINAL COST	**20.8**	**$/kW**	**45.4**	**$/WCUST**

Notes: 1 - Primary Investment and allocation between Demand and Customer is determined in Schedule 16.
2 - Escalation Index taken from Statistics Canada's Utility Construction Price Indices.
3 - Actual Historical Peaks for Newfoundland Power.
4 - Weighted Customers based on actual number of customers and the weighting factors shown in Schedule 22.

MARGINAL COSTS ASSOCIATED WITH SECONDARY FEEDERS
Based on Future Costs (All Costs X $1,000)

Year	Total Secondary Investment[1] Current$	Investment Allocated to Demand Growth Current$	Escalation to 1997[2]	Investment Allocated to Demand Growth 1997$	NP Peak Demand[3] MW	Increase in Peak[4] MW	Investment Allocated to Customer Growth Current$	Escalation to 1997[2]	Investment Allocated to Customer Growth 1997$	Average Weighted Customers[5] WCUST	Increase In Customers WCUST
1996					1,068					198.379	
1997	$682	$61	1.000	$61	1,086	18	$621	1.000	621	199.992	1.613
1998	$696	$64	0.990	$63	1,100	14	$633	0.990	626	201.798	1.807
1999	$655	$66	0.980	$64	1,119	19	$590	0.980	578	203.689	1.890
2000	$677	$68	0.971	$66	1,137	18	$609	0.971	591	205.770	2.081
TOTALS				$189	Growth trend	17.2			1,825		5.310

MARGINAL COSTS ASSOCIATED WITH NP'S DISTRIBUTION SECONDARY FEEDERS

		Demand Related		Customer Related	
a	Growth Investments (1997$)	189	(X $1,000)	1,825	(X $1,000)
b	Growth (For 4 Years)	69	MW	5,310	WCUST
c	Marginal Investment	2.75	$/kW	344	$/WCUST
d	Increm. Capitalized Gen. Expense (c X 9.6%)	0.22	$/kW	27.5	$/WCUST
e	General Plant Loading (c X 12.5%)	0.34	$/kW	43.0	$/WCUST
f	**Total Marginal Investment Cost**	**3.31**	**$/kW**	**414.3**	**$/WCUST**
g	Annualization Factor	9.09%		9.09%	
h	Plant Related Gen. Exp. Loading	0.27%		0.27%	
	Annualized Cost of Capital Additions	**0.31**	**$/kW**	**38.8**	**$/WCUST**
i	Marginal O&M Expense ((c+d) X 1.09%)	0.03	$/kW	4.0	$/WCUST
j	A & G Expense Loading Factor	1.30		1.30	
k	**Total Marginal O&M Expense**	**0.0**	**$/kW**	**5.3**	**$/WCUST**
	Working Capital				
l	Materials and Supplies (f X 0.46%)	0.02	$/kW	1.91	$/WCUST
m	Prepayments (f X 0.28%)	0.01	$/kW	1.16	$/WCUST
n	Cash Working Capital Allow. (k X 1.7%)	0.00	$/kW	0.09	$/WCUST
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%)	0.00	$/kW	0.41	$/WCUST
	Total Marginal Working Capital	**0.00**	**$/kW**	**0.4**	**$/WCUST**
	TOTAL MARGINAL COST	**0.35**	**$/kW**	**44.5**	**$/WCUST**

Notes: 1 - Total Secondary Investment and allocation between Demand and Customer is determined in Schedule 16.
2 - Escalation based on 0% Labour Escalations and 2% Material Escalation for an average of 1.0%.
3 - Taken from the Energy Supply Forecast, October 1996.
4 - A simple linear regression is used to determine the growth trend within the peak demands.
5 - Weighted Customers based on forecast of customers and the weighting factors shown in Schedule 22.

MARGINAL COSTS ASSOCIATED WITH SECONDARY FEEDERS

Based on Historical Costs (All Costs X $1,000)

Year	Total Secondary Investment[1] Current$	Investment Allocated to Demand Growth Current$	Escalation to 1997[2]	Investment Allocated to Demand Growth 1997$	NP Peak Demand[3] MW	Increase in Peak MW	Investment Allocated to Customer Growth Current$	Escalation to 1997[2]	Investment Allocated to Customer Growth 1997$	Average Weighted Customers[4] WCUST	Increase In Customers WCUST
1991					1,100					185,342	
1992	$995	$90	1.152	$104	1,027	(73)	$904	1.152	1,042	188,624	3,283
1993	$1,280	$127	1.124	$143	1,098	71	$1,153	1.124	1,295	191,509	2,885
1994	$935	$92	1.087	$100	1,031	(67)	$844	1.087	917	194,304	2,795
1995	$445	$43	1.034	$44	1,123	92	$402	1.034	416	196,576	2,272
1996	$791	$78	1.026	$80	1,081	(42)	$713	1.026	732	198,379	1,804
TOTALS				$346	Growth trend	3.6			3,254		8,962

MARGINAL COSTS ASSOCIATED WITH NP'S DISTRIBUTION SECONDARY FEEDERS

		Demand Related	Customer Related
a	Growth Investments (1997$)	346 (X $1,000)	3,254 (X $1,000)
b	Growth (For 5 Years)	18 MW	8,962 WCUST
c	Marginal Investment	19 $/kW	363 $/WCUST
d	Increm. Capitalized Gen. Expense (c X 9.6%)	1.8 $/kW	34.9 $/WCUST
e	General Plant Loading (c X 12.5%)	2.4 $/kW	45.4 $/WCUST
f	**Total Marginal Investment Cost**	**23.5 $/kW**	**443.4 $/WCUST**
g	Annualization Factor	9.09%	9.09%
h	Plant Related Gen. Exp. Loading	0.27%	0.27%
	Annualized Cost of Capital Additions	**2.2 $/kW**	**41.5 $/WCUST**
i	Marginal O&M Expense ((c+d) X 1.09%)	0.2 $/kW	4.3 $/WCUST
j	A & G Expense Loading Factor	1.30	1.30
k	**Total Marginal O&M Expense**	**0.3 $/kW**	**5.6 $/WCUST**
	Working Capital		
l	Materials and Supplies (X 0.46%)	0.11 $/kW	2.04 $/WCUST
m	Prepayments (X 0.28%)	0.07 $/kW	1.24 $/WCUST
n	Cash Working Capital Allow. (O&M X 1.7%)	0.01 $/kW	0.10 $/WCUST
o	Revenue Req'd for Working Capital (X 13.02%)	0.02 $/kW	0.44 $/WCUST
	Total Marginal Working Capital	**0.0 $/kW**	**0.4 $/WCUST**
	TOTAL MARGINAL COST	**2.5 $/kW**	**47.6 $/WCUST**

Notes: 1 - Secondary Investment and allocation between Demand and Customer is determined in Schedule 16.
2 - Escalation Index taken from Statistics Canada's Utility Construction Price Indices.
3 - Actual Historical Peaks for Newfoundland Power.
4 - Weighted Customers based on actual number of customers and the weighting factors shown in Schedule 22.

NEWFOUNDLAND POWER
1997 MARGINAL COST

MARGINAL COSTS ASSOCIATED WITH DISTRIBUTION TRANSFORMERS

Based on Future Costs (All Costs X $1,000)

Year	Total Distribution Transformer Marginal Investment[1]	Escalation Growth[2]	Total to 1997 1997$	Investment Allocated to Demand Growth[3] 1997$	Investment Allocated to Customer Growth[3] 1997$	Forecasted Peak Demand[4] MW	Increase Growth MW	Average Weighted to 1997[5] WCUST	Increase In Growth WCUST
1996						1,067.6		226,611	
1997	$1,872	1.000	$1,872	$187	$1,685	1,086.0	18	228,448	1,837
1998	$1,695	0.980	$1,662	$166	$1,495	1,100.3	14	230,602	2,153
1999	$1,729	0.961	$1,661	$166	$1,495	1,119.1	19	232,854	2,253
2000	$1,763	0.942	$1,661	$166	$1,495	1,136.9	18	235,348	2,493
TOTALS				$686	$6,171	Growth Trend	17		8,737

MARGINAL COSTS ASSOCIATED WITH NP'S DISTRIBUTION TRANSFORMERS

		Demand Related		Customer Related	
a	Growth Investments (1997$)	685.67	(X $1,000)	6,171	(X $1,000)
b	Growth (For 4 Years)	68.68	MW	8,737	WCUST
c	Marginal Investment	9.98	$/kW	706	$/WCUST
d	Increm. Capitalized Gen. Expense (c X 9.6%)	0.80	$/kW	57	$/WCUST
e	General Plant Loading (c X 12.5%)	1.25	$/kW	88.3	$/WCUST
f	**Total Marginal Investment Cost**	**12.03**	**$/kW**	**851.1**	**$/WCUST**
g	Annualization Factor	0.09		0.1	
h	Plant Related Gen. Exp. Loading	0.27%		0.27%	
	Annualized Cost of Capital Additions	**1.13**	**$/kW**	**79.69**	**$/WCUST**
i	Marginal O&M Expense ((c+d) X 3.43%)	0.37	$/kW	26.17	$/WCUST
j	A & G Expense Loading Factor	1.30		1.30	
k	**Total Marginal O&M Expense**	**0.48**	**$/kW**	**34.0**	**$/WCUST**
	Working Capital				
l	Materials and Supplies (f X 0.46%)	0.06	$/kW	3.9	$/WCUST
m	Prepayments (f X 0.28%)	0.03	$/kW	2.38	$/WCUST
n	Cash Working Capital Allow. (k X 1.7%)	0.01	$/kW	0.58	$/WCUST
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%	0.01	$/kW	0.90	$/WCUST
	Total Marginal Working Capital	**0.01**	**$/kW**	**0.9**	**$/WCUST**
	TOTAL MARGINAL COSTS FOR TRANSFORMERS	1.62	$/kW	114.6	$/WCUST

Notes: 1 - Based on Five Year Forecast, November 1996 less replacements. Percent replacements based on historic information.
2 - Escalation based on 2% Material Escalation.
3 - Allocated using allocation factors shown in Schedule 2.
4 - Taken from the Energy Supply Forecast, October 1996.
5 - Weighted Customers based on forecast of customers and the weighting factors shown in Schedule 22.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

MARGINAL COSTS ASSOCIATED WITH DISTRIBUTION TRANSFORMERS

Based on Historical Costs (All Costs X $1,000)

Year	Growth Related Distribution Transformer Investment[1] 1997$	Investment Allocated to Demand Growth[2] 1997$	Investment Allocated to Customer Growth[2] 1997$	NP Peak Demand[3] MW	Increase in Peak MW	Average Weighted Customers[4] WCUST	Increase In Customers WCUST
1987				890		194,276	
1988	2,817	282	2,535	969	79	199,137	4,861
1989	3,763	376	3,386	1,106	137	204,483	5,346
1990	4,106	411	3,696	1,073	(33)	209,348	4,865
1991	2,805	280	2,524	1,100	27	213,317	3,969
1992	1,346	135	1,211	1,027	(73)	216,568	3,251
1993	1,497	150	1,347	1,098	71	219,587	3,019
1994	1,253	125	1,128	1,031	(67)	222,758	3,171
1995	1,264	126	1,138	1,123	92	224,929	2,171
1996	1,331	133	1,198	1,081	(42)	226,611	1,682
TOTALS		2,018	18,163	Growth Trend	14.7		32,335

MARGINAL COSTS ASSOCIATED WITH NP'S DISTRIBUTION TRANSFORMERS

		Demand Related		Customer Related	
a	Growth Investments (1997$)	2,018	(X $1,000)	18,163	(X $1,000)
b	Growth (For 9 Years)	132	MW	32,335	WCUST
c	Marginal Investment	15	$/kW	562	$/WCUST
d	Increm. Capitalized Gen. Expense (c X 9.6%)	1.5	$/kW	53.9	$/WCUST
e	General Plant Loading (c X 12.5%)	1.9	$/kW	70.2	$/WCUST
f	**Total Marginal Investment Cost**	**18.6**	**$/kW**	**685.9**	**$/WCUST**
g	Annualization Factor	9.07%		9.07%	
h	Plant Related Gen. Exp. Loading	0.27%		0.27%	
	Annualized Cost of Capital Additions	**1.7**	**$/kW**	**64.0**	**$/WCUST**
i	Marginal O&M Expense ((c+d) X 3.43%)	0.6	$/kW	21.1	$/WCUST
j	A & G Expense Loading Factor	1.30		1.30	
k	**Total Marginal O&M Expense**	**0.7**	**$/kW**	**27.5**	**$/WCUST**
	Working Capital				
l	Materials and Supplies (f X 0.46%)	0.09	$/kW	3.15	$/WCUST
m	Prepayments (f X 0.28%)	0.05	$/kW	1.92	$/WCUST
n	Cash Working Capital Allow. (k X 1.7%)	0.01	$/kW	0.47	$/WCUST
o	Revenue Req'd for Working Capital ((l+m+n) 13.02%)	0.02	$/kW	0.72	$/WCUST
	Total Marginal Working Capital	**0.0**	**$/kW**	**0.7**	**$/WCUST**
	TOTAL MARGINAL COSTS FOR TRANSFORMERS	**2.5**	**$/kW**	**92.2**	**$/WCUST**

Notes: 1 - Estimated net transformers addition times the current cost of transformer purchases.
2 - Allocated using allocation factors shown in Schedule 2.
3 - Actual System Peaks for Newfoundland Power
4 - Weighted Customers based on actual number of customers and the weighting factors shown in Schedule 22.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

MARGINAL COSTS ASSOCIATED WITH SERVICES
Based on Future Costs (All Costs X $1,000)

Year	Total Investment in New Services: Total Capital Additions[1] Current$	Escalation to 1997[2]	Total Capital Additions 1997$	Investment Allocated to Customer Growth[3] 1997$	Average Weighted Customers[4] WCUST	Increase In Customers WCUST
1996					200,124	
1997	$800	1.000	$800	$800	201,773	1,648
1998	$849	0.990	$841	$841	203,620	1,848
1999	$867	0.980	$850	$850	205,546	1,926
2000	$889	0.971	$863	$863	207,657	2,111
TOTALS				3,353		7,532

MARGINAL COST OF SERVICES

a	Growth Investments (1997$)	3,353	(X $1,000)
b	Growth	7,532	WCUST
c	Marginal Investment	445.2	$/WCUST
d	Increm. Capitalized Gen. Expense (c X 9.6%)	35.6	$/WCUST
e	General Plant Loading (c X 12.5%)	55.6	$/WCUST
f	**Total Marginal Investment Cost**	**536.4**	**$/WCUST**
g	Annualization Factor	9.07%	
h	Plant Related Gen. Exp. Loading	0.27%	
	Annualized Cost of Capital Additions	**50.1**	**$/WCUST**
i	Marginal O&M Expense ((c+d) X 1.09%)	5.2	$/WCUST
j	A & G Expense Loading Factor	1.30	
k	**Total Marginal O&M Expense**	**6.8**	**$/WCUST**
	Working Capital		
l	Materials and Supplies (X 0.46%)	0.16	$/WCUST
m	Prepayments (X 0.28%)	0.10	$/WCUST
n	Cash Working Capital Allow. (O&M X 1.7%)	0.12	$/WCUST
o	Revenue Req'd for Working Capital (X 13.02%)	0.05	$/WCUST
	Total Marginal Working Capital	**0.0**	**$/WCUST**
	TOTAL MARGINAL COSTS ASSOCIATED WITH SERVICES	57.0	$/WCUST

NOTES:
1 - Taken from the Five Year Forecast, November 1996.
2 - Escalation based on 0% Labour Escalations and 2% Material Escalation for an average of 1.0%.
3 - 100% of marginal service costs are related to the number of customers.
4 - Weighted Customers based on forecast of customers and the weighting factors shown in Schedule 22.

MARGINAL COSTS ASSOCIATED WITH SERVICES
Based on Historical Costs (All Costs X $1,000)

Year	Total Investment in New Services: Total Capital Additions[1] Current$	Escalation 1997$[2]	Total Capital Additions 1997$	Investment Allocated to Customer Growth[3] 1997$	Average Weighted Customers[4] WCUST	Increase In Customers WCUST
1991					187,169	
1992	1,298	1.152	1,495	1,495	190,439	3,270
1993	1,267	1.124	1,423	1,423	193,308	2,870
1994	1,173	1.087	1,275	1,275	196,128	2,820
1995	977	1.034	1,010	1,010	198,348	2,220
1996	989	1.026	1,015	1,015	200,124	1,776
TOTALS				6,218		12,955

MARGINAL COST OF SERVICES

a	Growth Investments (1997$)	6,218	(X $1,000)
b	Growth	12,955	WCUST
c	Marginal Investment	480.0	$/WCUST
d	Increm. Capitalized Gen. Expense (c X 9.6%)	46.1	$/WCUST
e	General Plant Loading (c X 12.5%)	60.0	$/WCUST
f	**Total Marginal Investment Cost**	**586.1**	**$/WCUST**
g	Annualization Factor	9.64%	
h	Plant Related Gen. Exp. Loading	0.27%	
	Annualized Cost of Capital Additions	**58.1**	**$/WCUST**
i	Marginal O&M Expense ((c+d) X 1.09%)	5.7	$/WCUST
j	A & G Expense Loading Factor	1.30	
k	**Total Marginal O&M Expense**	**7.5**	**$/WCUST**
	Working Capital		
l	Materials and Supplies (f X 0.46%)	2.70	$/WCUST
m	Prepayments (f X 0.28%)	1.64	$/WCUST
n	Cash Working Capital Allow. (k X 1.7%)	0.13	$/WCUST
o	Revenue Req'd for Working Capital ((l+m+n) X 13.02%)	0.58	$/WCUST
	Total Marginal Working Capital	**0.6**	**$/WCUST**
	TOTAL MARGINAL COSTS ASSOCIATED WITH SERVICES	**66.1**	**$/WCUST**

NOTES:
1 - Actual Expenditures Associated with Services and Meter installation less Service replacements.
2 - Escalation Index taken from Statistics Canada's Utility Construction Price Indices.
3 - 100% of marginal service costs are related to the number of customers.
4 - Weighted Customers based on actual number of customers and the weighting factors shown in Schedule 22.

MARGINAL COSTS ASSOCIATED WITH METERS

Based on the current cost of meters

MARGINAL COST OF METERS

a	Marginal Investment[1]	43.7	$/WCUST
b	Increm. Capitalized Gen. Expense (c X 9.6%)	4.2	$/WCUST
c	General Plant Loading (a X 12.5%)	5.5	$/WCUST
d	**Total Marginal Investment Cost**	**53.3**	**$/WCUST**
e	Annualization Factor	12.14%	
f	Plant Related Gen. Exp. Loading	0.27%	
	Annualized Cost of Capital Additions	**6.6**	**$/WCUST**
g	Marginal O&M Expense ((c+d) X 5.86%)	2.81	$/WCUST
h	A & G Expense Loading Factor	1.30	
i	**Total Marginal O&M Expense**	**3.6**	**$/WCUST**
	Working Capital		
j	Materials and Supplies (d X 0.46%)	0.25	$/WCUST
k	Prepayments (d X 0.28%)	0.15	$/WCUST
l	Cash Working Capital Allow. (i X 1.7%)	0.06	$/WCUST
m	Revenue Req'd for Working Capital ((j+k+m) X 13.02%)	0.06	$/WCUST
	Total Marginal Working Capital	**0.1**	**$/WCUST**
	TOTAL MARGINAL COSTS ASSOCIATED WITH METERS	**10.3**	**$/WCUST**

NOTES:

1 - Marginal investment based on the cost of a new kilowatt hour meter for domestic customers.

MARGINAL COSTS ASSOCIATED WITH CUSTOMER RELATED EXPENSES
Based on Historical Operating Costs (All Costs X $1,000)

Year	O&M[1] Current$	Escalation[2] to 1997$	O&M 1997$	Average Weighted Customers[3] WCUST	Unit Customer Cost $/WCUST
1992	11,630	1.152	13,398	207,859	64.5
1993	11,870	1.124	13,337	211,127	63.2
1994	8,843	1.087	9,614	214,350	44.8
1995	9,299	1.034	9,613	216,994	44.3
1996	9,247	1.026	9,487	219,106	43.3
Three Year Average Unit Cost [4]					44.2

a Marginal Operating Expenses for Customer Service	44.2	$/WCUST
b A & G Expense Loading Factor	1.30	
c **Total Marginal O&M Expense**	**57.4**	**$/WCUST**
Working Capital		
d Cash Working Capital Allow. (c X 1.7%)	0.98	
e Revenue Req'd for Working Capital (d 13.02%)	0.13	
Total Marginal Working Capital	**0.1**	**$/WCUST**
TOTAL MARGINAL COSTS ASSOCIATED WITH SERVICES	**57.5**	**$/WCUST**

NOTES:
1 - Taken from Year End Accounting Reports.
2 - Escalation Index taken from Statistics Canada's Utility Construction Price Indices for Distribution.
3 - Weighted Customers based on actual number of customers and the weighting factors shown in Schedule 22.
4 - Average of only three years taken because of centralization of Customer Service with NP resulted in significant efficiency improvements in 1994.

ENERGY LOSS ADJUSTMENT FACTORS[1]

	Losses to Generation as % of Sales			
	On-Peak	Off-Peak	Winter	Summer
Secondary Customer	1.1009	1.0716	1.0936	1.0700
Primary Customer	1.0743	1.0516	1.0687	1.0503
Transmission	1.0420	1.0335	1.0397	1.0332

PEAK LOAD LOSS ADJUSTMENT FACTORS

	Losses to NP's System Peak	Losses to Island Interconnected Peak
Secondary Sales	1.0910	1.1292
Primary Sales	1.0583	1.0954
Transmission Sales	1.0159	1.0515

NOTES:

1 - Based on the following data:
- NP's annual system loss allocation analysis
- a technical review of no load losses
- loss information contained in Hydro's Cost of Service Study
- analysis of loading levels during on-peak and off-peak periods and, analysis of loading levels during the winter season and summer season.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

ALLOCATION OF FORECAST CAPITAL TO PRIMARY AND SECONDARY FEEDERS
Based on Future Costs (All Costs X $1,000)

FUNCTIONAL CLASSIFICATION OF GROWTH RELATED TRUNK FEEDER PROJECTS

Year	Growth Related Trunk Feeder Additions[1]	Allocations[2] Portion to Demand	Demand Primary	Demand Secondary	Portion to Customer	Customer Primary	Customer Secondary
1997	$469	$111	$111	$0	$358	$286	$72
1998	$417	$129	$129	$0	$288	$230	$58
1999	$110	$110	$110	$0	$0	$0	$0
2000	$110	$422	$422	$0	$0	$0	$0

FUNCTIONAL CLASSIFICATION OF DISTRIBUTION EXTENSIONS PROJECTS

Year	Growth Related Extensions Additions[3]	Estimated CIAC[4]	Net Additions	Allocations[5] Portion to Demand	Demand Primary	Demand Secondary	Portion to Customer	Customer Primary	Customer Secondary
1997	2,120	1,010	1,110	$111	$50	$61	$999	$450	$549
1998	2,218	1,056	1,162	$116	$52	$64	$1,045	$470	$575
1999	2,275	1,084	1,191	$119	$54	$66	$1,072	$483	$590
2000	2,349	1,119	1,230	$123	$55	$68	$1,107	$498	$609

NOTES:
1 - A detailed review of trunk feeder projects within the five year capital forecast (Nov. 96) identified growth related items.
2 - The allocation factors used are shown in Schedule 2.
3 - The numbers were taken from the five year capital forecast, November 1996.
4 - CIAC estimated based on portion of extensions budget recovered through CIAC in the past.
See Schedule 16, page 2 of 2.
5 - The allocation factors used are shown in Schedule 2.

ALLOCATION OF FORECAST CAPITAL TO PRIMARY AND SECONDARY FEEDERS
Based on Historic Costs (All Costs X $1,000)

FUNCTIONAL CLASSIFICATION OF GROWTH RELATED TRUNK FEEDER PROJECTS

Year	Growth Related Trunk Feeder Additions[1]	Allocations[2]					
		Portion to Demand	Demand Primary	Demand Secondary	Portion to Customer	Customer Primary	Customer Secondary
1992	$1,643	$1,182	$1,182	$0	$461	$368	$92
1993	$630	$582	$582	$0	$48	$38	$10
1994	$605	$508	$508	$0	$96	$77	$19
1995	$206	$117	$117	$0	$88	$71	$18
1996	$155	$93	$93	$0	$62	$50	$12

FUNCTIONAL CLASSIFICATION OF EXTENSIONS PROJECT PROJECTS

Year	Growth Related Extensions Additions[3]	Actual CIAC[4]	Net Additions	Allocations[5]					
				Portion to Demand	Demand Primary	Demand Secondary	Portion to Customer	Customer Primary	Customer Secondary
1992	3,361	1,720	1,641	$164	$74	$90	$1,477	$665	$812
1993	3,307	997	2,310	$231	$104	$127	$2,079	$935	$1,143
1994	2,979	1,314	1,665	$167	$75	$92	$1,499	$675	$824
1995	2,652	1,875	777	$78	$35	$43	$699	$315	$385
1996	2,613	1,197	1,416	$142	$64	$78	$1,274	$574	$701
Total	14,913	7,103							
% CIAC		47.6%							

NOTES:

1 - A detailed review of trunk feeder projects work orders identified growth related items.
2 - The allocation factors used are shown in Schedule 2.
3 - The numbers were taken from year end accounting reports.
4 - CIAC is taken from the annual report to the Public Utilities Board, adjusted for CIAC associated with transmission additions.
5 - The allocation factors used are shown in Schedule 2.

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

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.

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

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

- Average Escalation Rate (GDP Deflator)[2] = 2.30%
- Escalation of Metering Equipment[3] = 0.00%

- Discount Rate for determining E.C.C. for NP's assets[4] = 7.55%
- Discount Rate for determining E.C.C. for NLH's assets[4] = 9.40%

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

Asset Type	K[5]	Life	$E.C.C._0$	Financing
Gas Turbine	1.027	25	8.20%	NLH Straight Line Depr.
NLH TMS Common	1.043	45	7.12%	NLH Sinking Fund
NLH TMS Specif. Assigned	1.043	45	7.12%	NLH Sinking Fund
NLH Term Station	1.034	40	7.20%	NLH Straight Line Depr.
NLH Hydro	1.043	75	6.81%	NLH Sinking Fund
NP Transmission	1.542	40	8.71%	NP Straight Line Depr.
NP Substation	1.539	35	9.09%	NP Straight Line Depr.
NP Trunk Feeders	1.539	35	9.09%	NP Straight Line Depr.
NP Distribution Transformers	1.534	35	9.07%	NP Straight Line Depr.
NP Services	1.534	30	9.64%	NP Straight Line Depr.
NP Meters	1.534	30	12.14%	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 - It is assumed that all cost except metering hardware will escalation according to the forecasted GDP deflator series for Canada shown in schedule 21.
3 - Due to technological improvments, no escalation is assumed for the cost of meters.
4 - 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.
5 - 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.

DEVELOPMENT OF ADMINISTRATION AND GENERAL EXPENSE LOADER

All Costs Taken from Year End Acounting Reports

		1992	1993	1994	1995	1996
Total O&M Expenses After Transfers to GEC		$244,187,455	$241,586,958	$242,996,422	$246.465.934	$244.987.456
Total A&G Expenses	Marginal	$8,876,819	$8,596,703	$8,706,167	$8,679,195	$10,439.993
	Non-Marginal	$9,341,025	$9,337,481	$9,489,632	$12,809,928	$12.106,777
Total Purchase Power		$191,370,141	$191,422,945	$191,641,390	$191,599,636	$190.251,070
Total O&M less A&G less Purchase Power		$34,599,470	$32,229,829	$33,159,232	$33,377,174	$32,189,616
Total A&G as % of Expenses						
	Marginal[1]	25.66%	26.67%	26.26%	26.00%	32.43%
	Non-Marginal[2]	27.00%	28.97%	28.62%	38.38%	37.61%
	Total	52.65%	55.64%	54.87%	64.38%	70.04%
Marginal A&G Loader[3]		**30%**				

GENERAL EXPENSES CAPITAL LOADER

- After Transition to Incremental GEC the amount of general expenses transfered to Capital will be about[4]:	$2,700,000
- The Capital Budget (before GEC) is expected to be around[4]:	$28,000,000
Estimated average GEC Rate:	**9.64%**

NOTES:

1 - Includes Administration and General expense such as Labour Overheads, Training, Computer User Support, etc. It was based on those items that can be expected to vary with changes in labour and number of customers.
2 - It excluded all administration and general costs not included under Note 1.
3 - The loading reflects that the 1996 marginal A&G cost is higher due to incentive pay increasing. this increase reflects inclusion of union labour into the incentive plan.
4 - Based on Current Projections for 1999, the first year after the transition to incremental GEC is complete.

CALCULATION OF A PLANT LOADER FOR PLANT RELATED GENERAL O&M

	1992	1993	1994	1995	1996	Source
Plant Investment	$714,310,000	$742,440,000	$772,592,000	$796,574,000	$816,257,000	Annual Report To Board
Total Plant Related O&M	$2,061,919	$2,102,416	$2,199,005	$2,102,854	$1,945,944	From Expense Reports
Plant Loading Factor	0.29%	0.28%	0.28%	0.26%	0.24%	
Average Plant Loading Factor	**0.27%**					

CALCULATION OF A PLANT LOADER FOR GENERAL PLANT

	1992	1993	1994	1995	1996	Source
Gross Plant Investment	$714,310,000	$742,440,000	$772,592,000	$796,574,000	$816,257,000	
General Plant						
Land and land rights	$5,616,678	$5,615,478	$5,615,478	$5,611,944	$5,534,488	Details of Property Plant & Equ.
Buildings and structures	$29,221,971	$29,371,572	$29,206,152	$30,055,322	$28,206,961	Details of Property Plant & Equ.
Office equipment	$3,730,667	$3,753,089	$4,042,927	$4,675,308	$4,654,599	Details of Property Plant & Equ.
Computer Hardware	$6,186,533	$5,029,935	$5,174,432	$5,608,008	$6,560,412	Details of Property Plant & Equ.
Computer Software	$12,837,197	$15,380,738	$16,087,209	$16,594,984	$17,473,287	Details of Property Plant & Equ.
Stores equipment	$818,255	$822,811	$519,873	$611,930	$650,319	Details of Property Plant & Equ.
Shop equipment	$435,294	$456,942	$485,768	$529,530	$567,915	Details of Property Plant & Equ.
Labratory test equipment	$1,950,710	$2,082,584	$2,255,167	$2,900,193	$3,165,902	Details of Property Plant & Equ.
Miscellaneous	$2,915,183	$2,861,715	$3,591,846	$1,627,165	$1,733,812	Details of Property Plant & Equ.
Engineering equipment	$362,816	$366,748	$366,748	$367,455	$369,995	Details of Property Plant & Equ.
Transportation equipment	$17,587,142	$17,593,620	$18,643,877	$20,064,472	$19,496,627	Details of Property Plant & Equ.
TOTAL	$81,662,446	$83,335,232	$85,989,477	$88,646,311	$88,414,317	Details of Property Plant & Equ.
Plant Without General Property	$632,647,554	$659,104,768	$686,602,523	$707,927,689	$727,842,683	
General Plant Loader	12.91%	12.64%	12.52%	12.52%	12.15%	
Average General Plant Loader	**12.5%**					

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

CALCULATION OF A PLANT LOADING FOR MATERIALS AND SUPPLIES

	1992	1993	1994	1995	1996	Source
Plant Investment	$714,310,000	$742,440,000	$772,592,000	$796,574,000	$816,257,000	Annual Report To Board
Material and Supplies	$4,484,000	$3,670,000	$3,515,000	$3,605,000	$3,498,000	Return 7A Report To Board
Plant Loading Factor	0.63%	0.49%	0.45%	0.45%	0.43%	
Avg. Plant Loading 1993 - 1996	**0.46%**					

CALCULATION OF A PLANT LOADER FOR PREPAYMENTS

	1992	1993	1994	1995	1996	Source
Gross Plant Investment	$714,310,000	$742,440,000	$772,592,000	$796,574,000	$816,257,000	Annual Report To Board
Prepayed Expenses	$1,690,000	$3,596,000	$2,404,000	$1,627,000	$1,276,000	Balance Sheet Statement
General Plant Loader	0.24%	0.48%	0.31%	0.20%	0.16%	
Average General Plant Loader	**0.28%**					

DERIVATION OF REVENUE REQUIREMENT FOR WORKING CAPITAL

	Incremental Capital Structure	Incremental Cost of Capital	Income Tax Component Cost of Capital	Weighted Cost of Capital
Debt	52.00%	8.00%	0.00%	4.16%
Preferred	3.00%	6.33%	4.58%	0.33%
Common Equity	45.00%	11.00%	7.97%	8.53%
Revenue Requirement for Working Capital Factor				**13.02%**

Cash Working Capital Allocation Factor **1.7% Taken from Annual Report to Board (Return 7).**

TOTAL O&M BY ASSET GROUP

Year	Transmission	Substations	Distribution Primary and Secondary	Distribution Transformers	Services	Meters
1992	$754,079	$2,907,599	$5,274,624	$2,432,869	$1,828,949	$1,542.549
1993	$642,995	$2,778,529	$4,304,711	$2,249,465	$1,746.478	$1.462.175
1994	$1,416,515	$2,947,618	$5,813,886	$2,190,344	$2,144,139	$1,344,151
1995	$904,782	$3,412,291	$5,598,821	$1,993,539	$2,126,729	$1,288.686
1996	$1,392,373	$3,399,110	$3,697,371	$2,246,876	$2,583,714	$1,358.944

VALUE OF PLANT IN SERVICE ESCALATED TO APPLICABLE YEAR (BASED ON INSURABLE PROPERTY ESTIMATES)

Year	Transmission	Substations	Distribution Plant Less Transformers Meters and Street Lighting	Transformers Padmounted and Pole Mounted Transformers	Meters
1992	N/A	N/A	N/A	N/A	N/A
1993	142,852,021	168,624,213	572,176,267	60,620,471	24,303,443
1994	151,695,529	174,422,414	619,185,103	63,803,013	23,074,860
1995	160,054,426	184,883,607	653,700,443	63,274,200	22,759,015
1996	167,094,897	184,068,945	671,606,315	65,414,361	22,908,126

N/A - Not Available

O&M AS A PERCENT OF PLANT

Year	Transmission	Substations	Distribution Primary Secondary and Services	Transformers Padmounted and Pole Mounted Transformers	Meters
1992	N/A	N/A	N/A	N/A	N/A
1993	0.45%	1.65%	1.07%	3.71%	6.02%
1994	0.93%	1.69%	1.22%	3.43%	5.83%
1995	0.57%	1.85%	1.18%	3.15%	5.66%
1996	0.83%	1.85%	0.87%	3.43%	5.93%
AVERAGE	0.70%	1.76%	1.09%	3.43%	5.86%

NEWFOUNDLAND POWER
1997 MARGINAL COST STUDY

FUEL AND O&M ESCALATION INDEX FORECAST

	Conference Board of Canada		
Year	Holyrood Fuel Forecast[1] $/BBL	C.T. Fuel Cost[2] ¢/l	Canada GDP Deflator Index3 (1986=$1.00)
			1.255
1997	22.10	23.0	1.288
1998	22.10	23.0	1.311
1999	22.50	23.4	1.336
2000	23.30	24.2	1.368
2001	24.10	25.1	1.399
2002	21.60	22.5	1.434
2003	22.60	23.5	1.469
2004	23.90	24.9	1.507
2005	25.10	26.1	1.547
2006	26.50	27.6	1.587
2007	28.10	29.2	1.628
2008	29.90	31.1	1.671
2009	31.70	33.0	1.713
2010	33.70	35.1	1.752
2011	36.00	37.5	1.791
2012	38.20	39.8	1.830
2013	40.60	42.3	1.869
2014	42.70	44.4	1.908
2015	44.60	46.4	1.948
% Esc. 1996 - 2015	3.84%	3.76%	2.30%

NOTES:
1 - Fuel Forecast for Holyrood Fuel Estimated by the Conference Board of Canada, March 7 1997.
2 - #2 Diesel Fuel projected based on Holyrod fuel forecast using 23 cent/litre for 1997.
3 - GDP Deflator Index Forecast for Canada provided by the Conference Board of Canada on December 10, 1996

CUSTOMER WEIGHTING FACTORS[1]

	New Customer Related Extensions Primary	New Customer Related Extensions Secondary	Distribution Transformers	Services & Meter Installations	Meter Hardware	Customer Service Cost
RATE 1.1: GENERAL DOMESTIC	1.00	1.00	1.00	1.00	1.00	
RATE 2.1: GENERAL SERVICE < 10 kW						
Single Phase Customer	1.00	1.00	1.00	1.00	1.00	
Three Phase Customer	1.00	1.00	4.07	1.04	8.85	
RATE 2.2: GENERAL SERVICE (Between 10 kW and 100 kW-110kVA)						
Single Phase Customer	1.00	1.00	2.00	1.11	5.30	
Three Phase Customer	1.00	1.00	4.07	0.72	10.40	
RATE 2.3: GENERAL SERVICE (Between 110 kVA and 350 kVA)						
Secondary Customer						
Single Phase	1.00	1.00	8.18	1.09	15.41	
Three Phase	1.00	1.00	11.49	3.07	59.49	
Primary Customer	1.00	1.00	0.00	1.83	218.14	
RATE 2.3: GENERAL SERVICE (Between 350 kVA and 1000 kVA)						
Secondary Customer	1.00	1.00	20.77	3.07	59.49	
Primary Customer	1.00	0.00	0.00	1.83	218.14	
Transmission Customer	0.00	0.00	0.00	1.97	243.59	
RATE 2.4: GENERAL SERVICE (> 1000 kVA)						
Secondary Customer	1.00	1.00	44.80	3.87	219.22	
Primary Customer	1.00	0.00	0.00	1.92	253.83	
Transmission Customer	0.00	0.00	0.00	1.36	154.32	
RATE 4.1: STREETLIGHTING	0.00	0.00	0.20	0.00	0	

NOTES:

1 - Weighting Factors based on estimates of the cost to provide service to an average customer.

APPENDIX D

CANADIAN UTILITY SURVEY OF INNOVATIVE RATES

SURVEY OF MARGINAL COST BASED RATE OPTIONS OFFERED BY CANADIAN ELECTRIC UTILITIES

1.0 Purpose of the Survey

The survey was done to collect information on the use of marginal costs in rate design, the availability of marginal cost based rates, and the level of customer participation in marginal cost based rates.

2.0 Conclusions

1. Most utilities do not give marginal costs significant consideration when deriving the endblock energy prices for their standard rates.

2. None of the utilities that responded offer residential seasonal rates, and the vast majority do not offer general service seasonal rates.

3. Time of day ("TOD") rates are more frequently available for large general service customers than for small general service customers and residential customers.

4. A small percentage of customers take advantage of TOD rates when given the opportunity (i.e., less than 0.1% participation rate for residential customers and less than 2% for general service customers).

5. Curtailable rates are offered by the majority of Canadian utilities (82%), while real-time pricing, stand-by-rates, and surplus energy rates are offered by 59%, 53% and 41% of the Canadian utilities respectively.

3.0 Data Collection Methodology

A questionnaire on rate design and rate options available to customers was sent to 20 of the larger Canadian electrical utilities during February 1997. Questionnaires were sent to the following utilities: B.C. Hydro, New Brunswick Power, Ontario Hydro, TransAlta Utilities, Maritime Electric, Ottawa Hydro, Public Utility Commission of Scarborough, City of Calgary Electric System, Edmonton Power, West Kootenay Power, Nova Scotia Power, Hydro Quebec, Manitoba Hydro, SaskPower, Hydro Mississauga, North York Hydro, Alberta Power, Toronto Hydro, Great Lakes Power, and NWT Power. Sixteen of the utilities contacted completed the questionnaire for a response rate of 80%. Including Newfoundland Power as a respondent brings the number of utilities to seventeen.

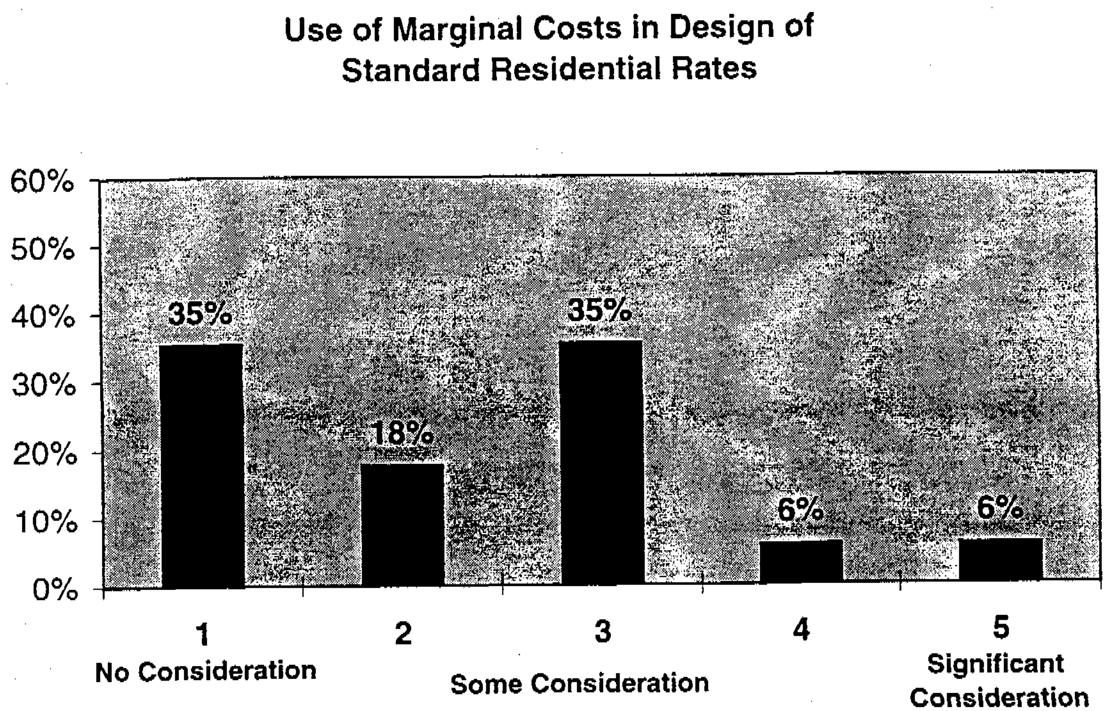
The questionnaire was arranged in three sections. The first section dealt with the use of marginal costs in the design of standard rates for residential and general service customers and whether seasonal price differences were included as part of the standard rate. The second section focused on the availability of TOD rates for residential, general service and wholesale customers. Information was gathered on whether the TOD rates were optional for all customers within a class or mandatory for customers with certain usage attributes. The third section gathered information on other innovative rates being offered, and the use of revenue recovery mechanisms for dealing with lost revenue as a result of the introduction of TOD rates. The data compiled also includes data for Newfoundland Power. The names of the utilities are withheld upon the request of the participants.

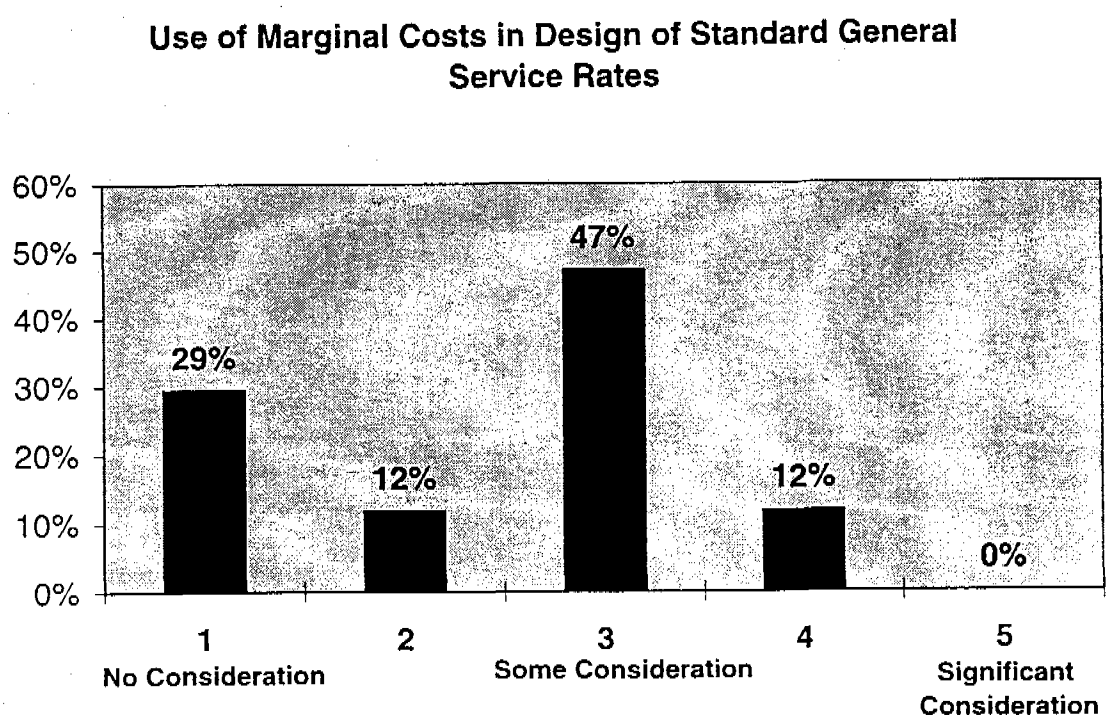
4.0 Terminology

To understand the discussion of the responses the following definitions are provided:
Standard Rate: A standard rate is defined as a rate schedule in which the price does not differ by time of day. For purposes of this questionnaire seasonal rates which fit this description are considered standard rates.
Time of Day Rate: A TOD rate is defined as a rate schedule which incorporates different rating periods and rates within a given day, typically designated as on-peak and off-peak periods. A demand charge is sometimes included in the rate design.

5.0 The Use of Marginal Costs in the Design of Standard Rates

Only two of the seventeen utilities indicated that significant consideration is given to marginal costs in determining the tail block energy rates for both the residential and general service classes.

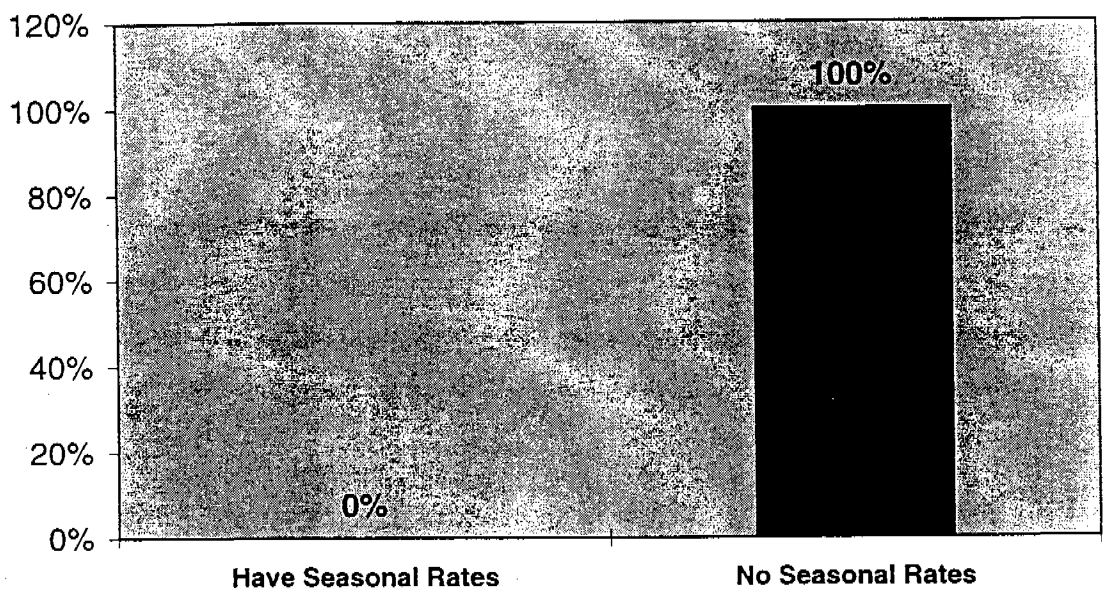




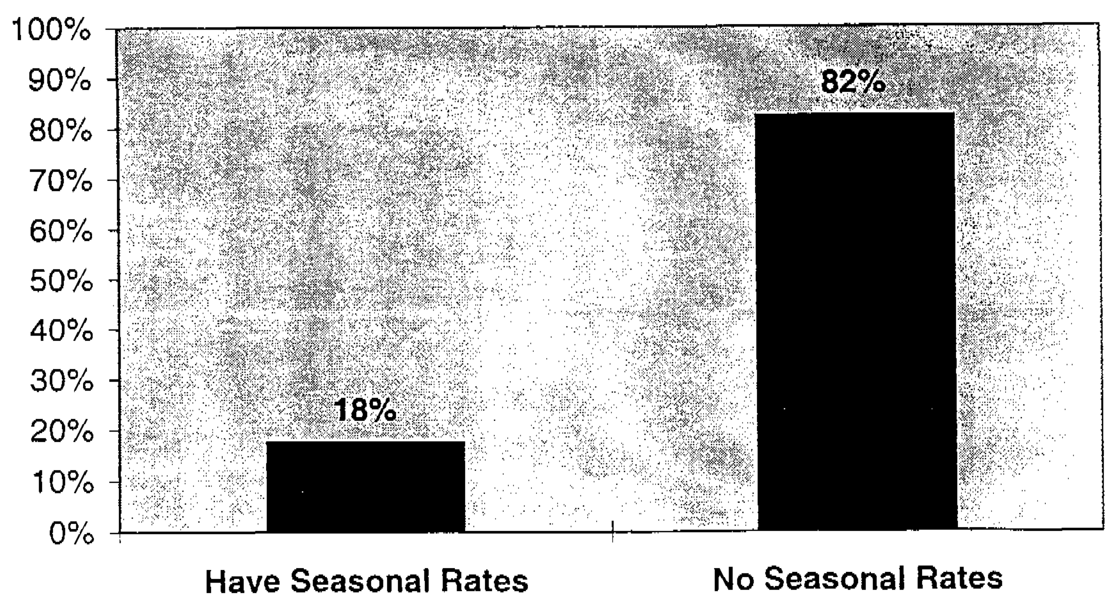
6.0 Seasonal Rates

None of the respondents have prices that differ by season in their residential standard rate and only three utilities, of which Newfoundland Power is one, have seasonal price differences within their general service standard rates.

Percent of Utilities with Residential Seasonal Rates

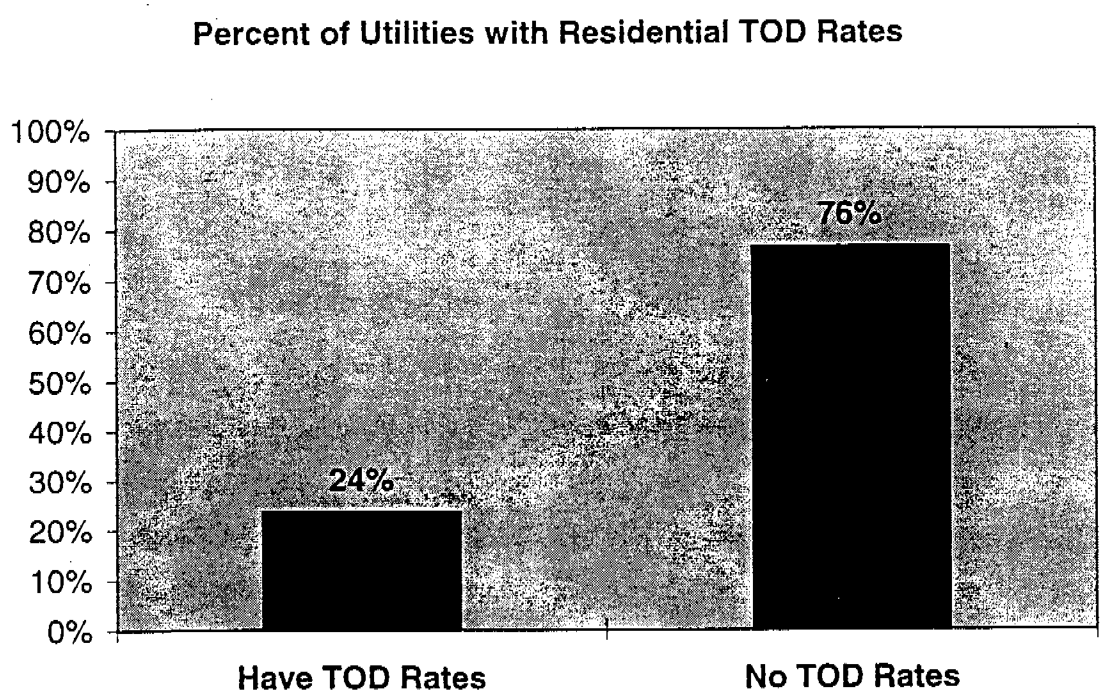


Percent of Utilities with General Service Seasonal Rates



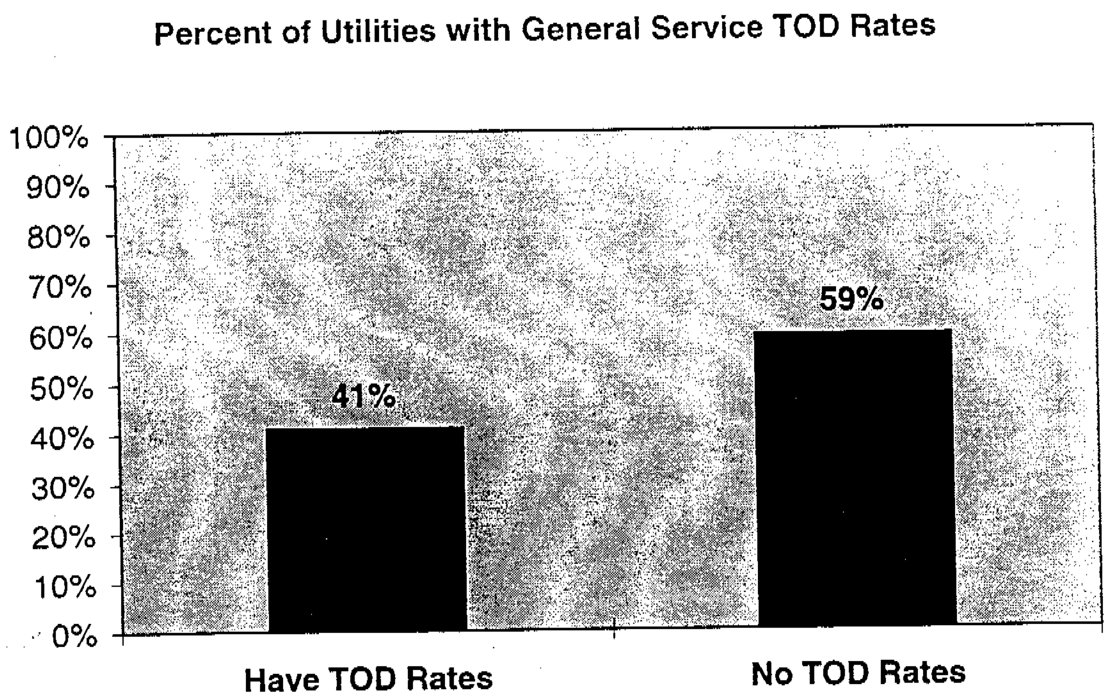
7.0 The Availability of TOD rates in Canada

Four of the respondents have TOD rates for residential customers. For customers of three of these utilities the rate is optional. For the other utility the rate is mandatory for customers with a utility supplied electric thermal storage heating system.



Seven of the respondents have TOD rates for General Service customers. Five of the seven utilities offering TOD rates to general service customers restrict their availability to larger customers, the smallest of which is 200 kVA. The other two utilities make TOD rates available to all general service customers. Three of the respondents make TOD rates mandatory for customers above certain demand requirements (i.e., usually large customers).

Three of the utilities that have TOD rates for general service customers also have TOD rates for wholesale customers (two optional and one mandatory).



8.0 Customer Participation on TOD Rates

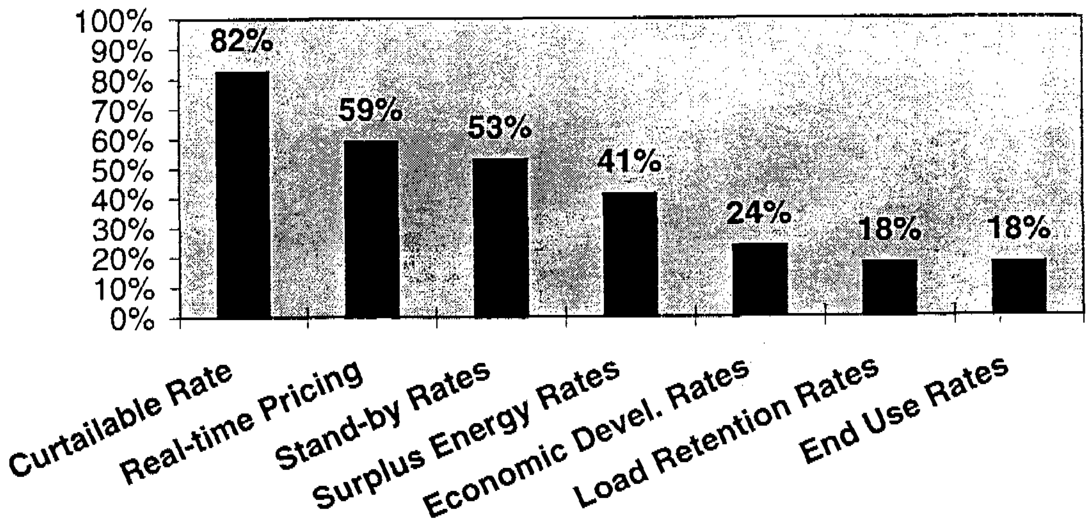
Of the four utilities that have TOD rates available to residential customers, only two currently have any customers billed on the TOD rate (i.e., 140 at one utility and approximately 230 at the other). The residential TOD rate has only recently been offered at one utility, which may explain why there are no customers on the rate for the utility.

The number of customers on the general service TOD rates ranges from 16 at one utility to 225 at another; while most utilities have 40 to 50 customers on the TOD rate. No utility offering TOD rates has more than 2% of their general service customers on TOD rates. Most have less than 0.25%.

9.0 Other Marginal Cost Based Rate Options

The response to the question on other innovative rate structures identified approximately 10 different structures used by Canadian utilities. Only two of these structures (i.e., dual fuel and end use rates) were available to residential customers. The bar chart below shows seven of the more popular innovative rate structures made available by Canadian utilities for large general service and wholesale customers.

Other Innovative Rates Offered by Utilities in Canada



10.0 Miscellaneous Information

Only one of the utilities currently offering TOD rates set up a mechanism to recover lost revenue when the TOD rates were first introduced.

Of the four utilities offering TOD rates to residential customers, two utilities increased the customer charge to recover the additional metering costs of TOD rates.

Three utilities have conducted load studies in an attempt to quantify the effects of TOD rates on customer usage patterns.

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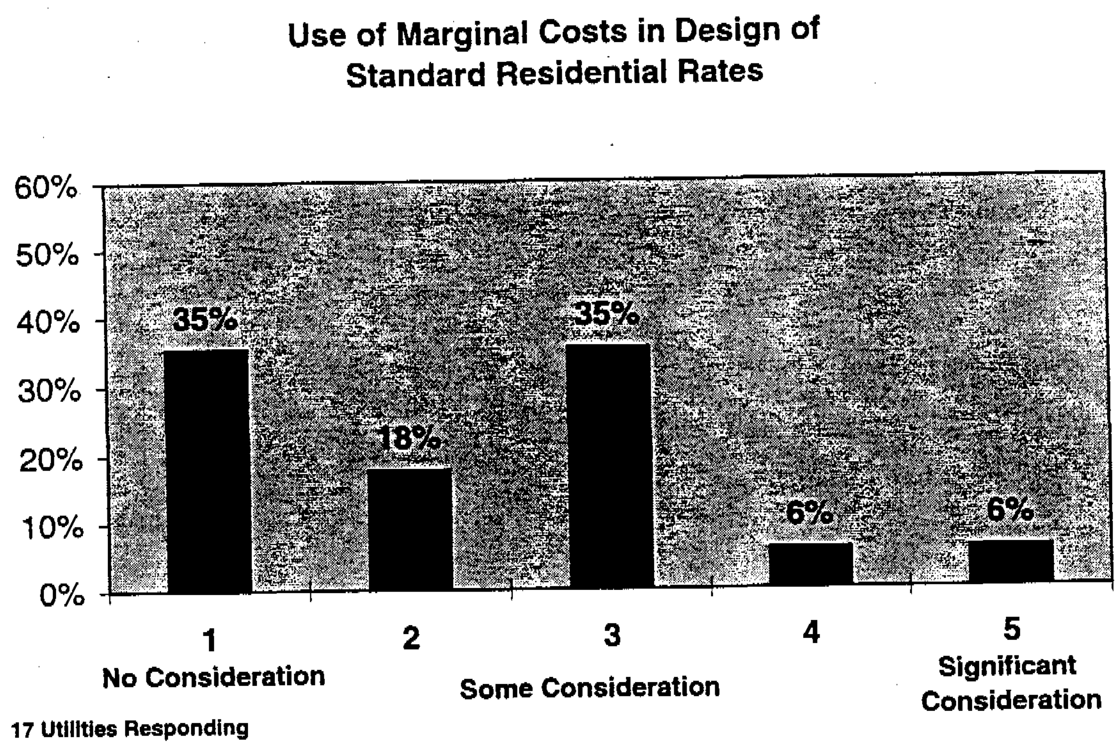

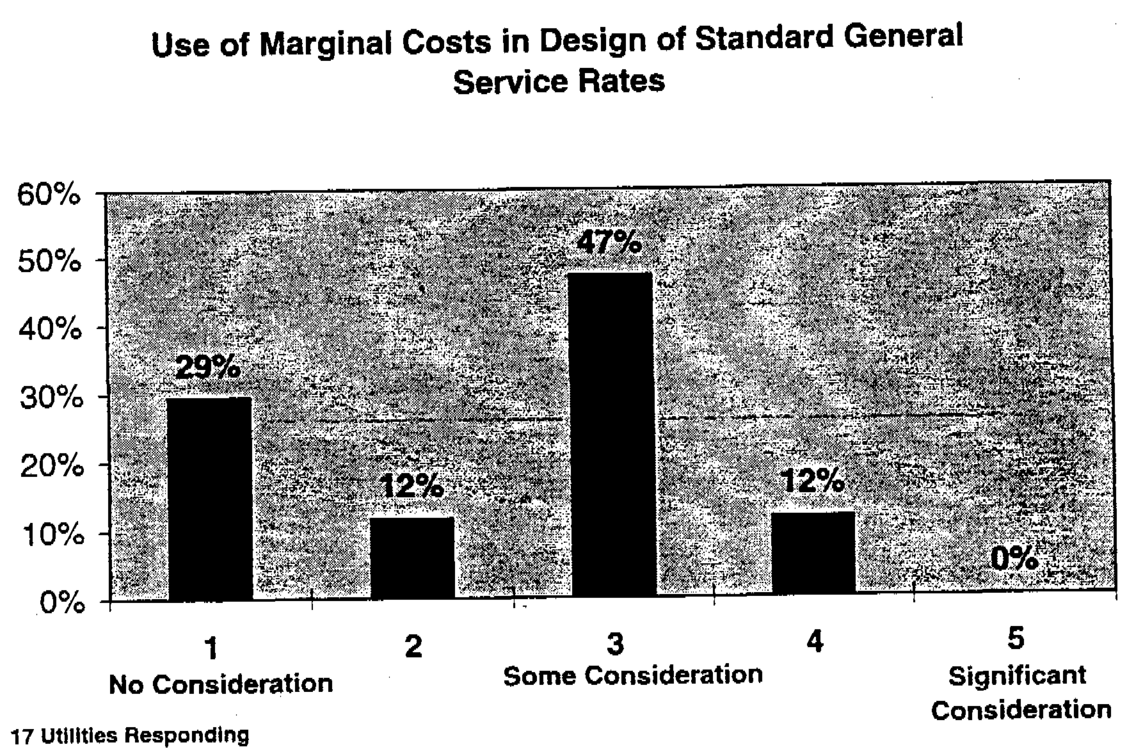

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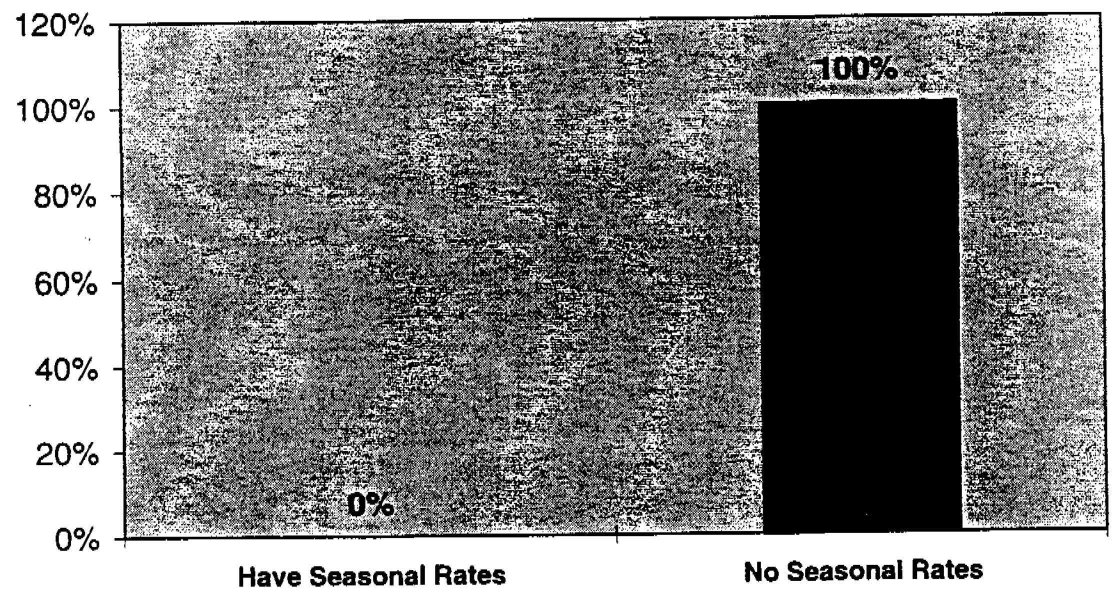
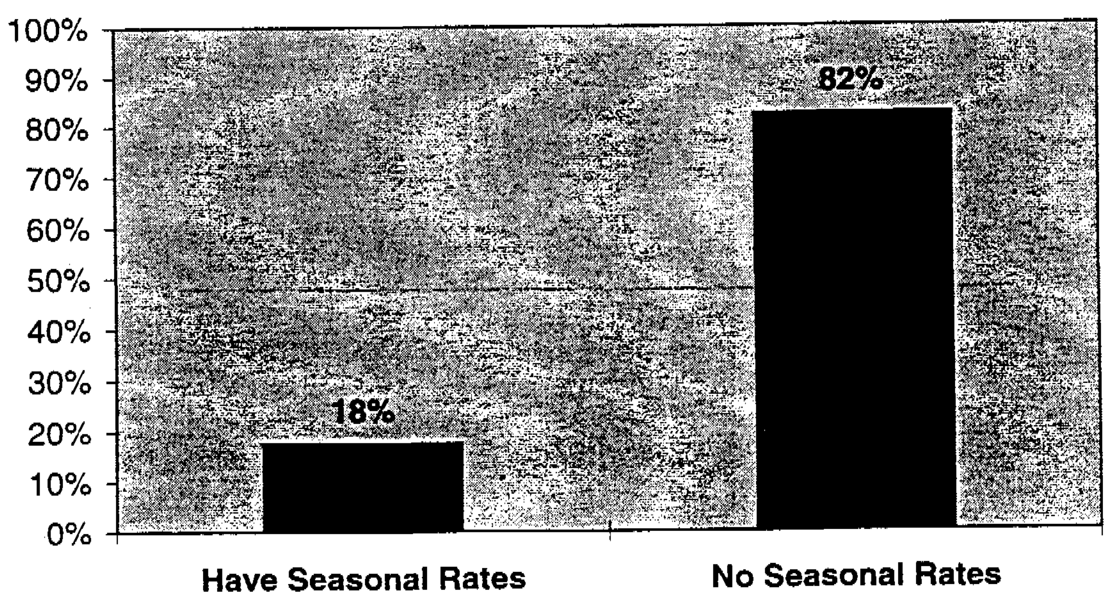


17 Utilities Responding

Percent of Utilities with General Service Seasonal Rates



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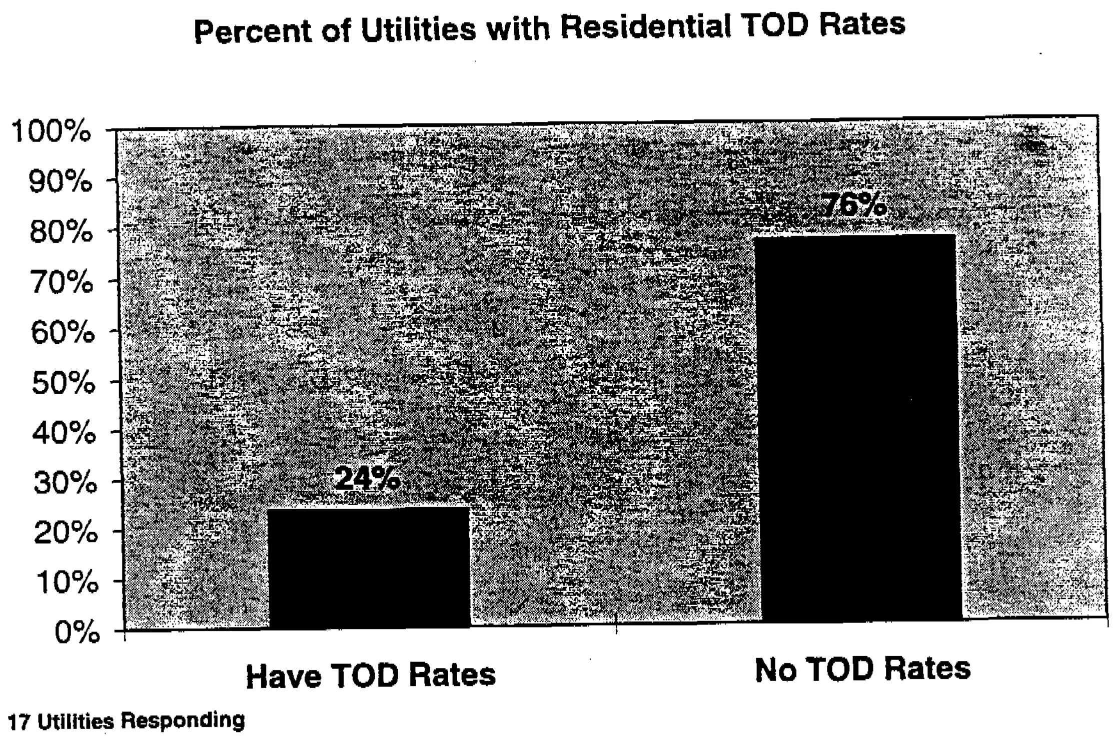

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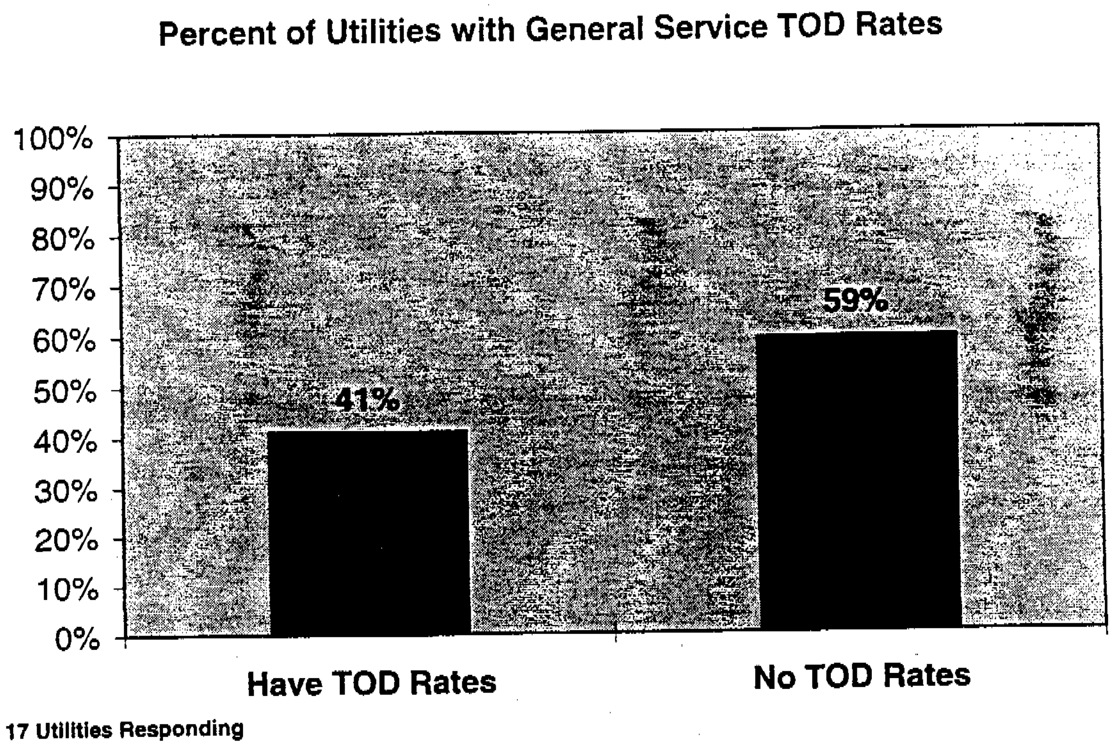

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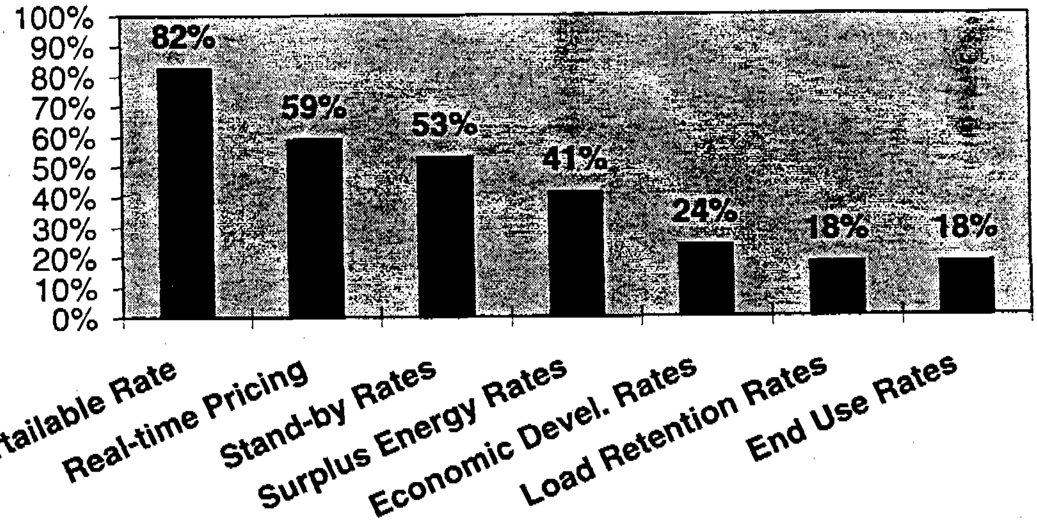

17 Utilities Responding

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Three utilities have conducted load studies in an attempt to quantify the effects of TOD rates on customer usage patterns.

APPENDIX E

RESIDENTIAL TIME-OF-DAY SURVEY OF U.S. AND CANADIAN UTILITIES

RESIDENTIAL TIME-OF-DAY SURVEY OF U.S. AND CANADIAN UTILITIES

Attached is a summary of a survey conducted in late 1993 by Virginia Power on residential time-of-day rates in the U.S. and Canada.

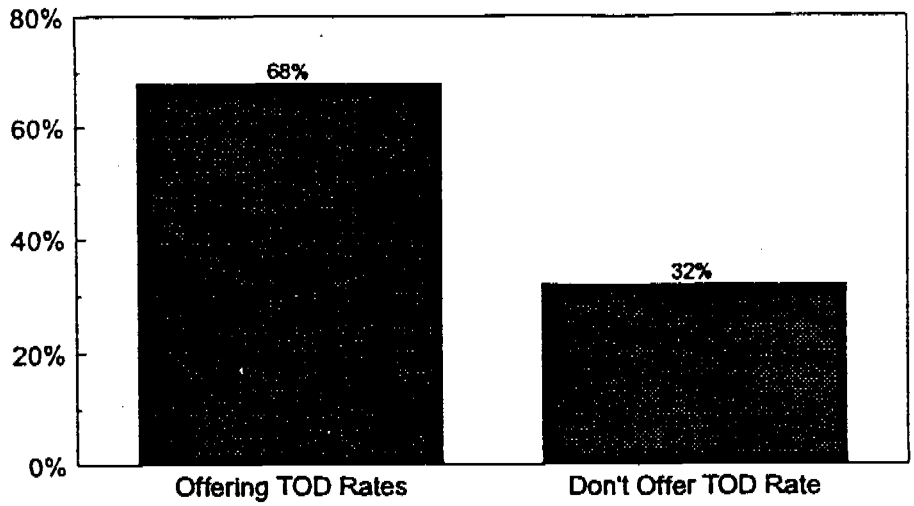
TIME-OF-DAY RATE SURVEY

A survey was conducted among electric utilities to assess their positions and feelings regarding time-of-day (TOD) rates for residential customers. Included were several questions regarding their utility's position with respect to mandatory residential TOD rates.

On September 1, 1993, a questionnaire was sent to 109 electric utilities located throughout the United States and Canada. The survey was sent to those utilities with representation in the Edison Electric Institute's Rate Research Committee. Ninety-two (92) responses were received, for a response rate of 84 percent. Sixty-three (63), or two-thirds, of the utilities have time-of-day rates available to their residential customers. Conversely, one-third of the utilities do not offer residential TOD rates. Of the sixty-three utilities offering TOD rates, fourteen (14) mandate TOD rates to a segment of their residential customers.

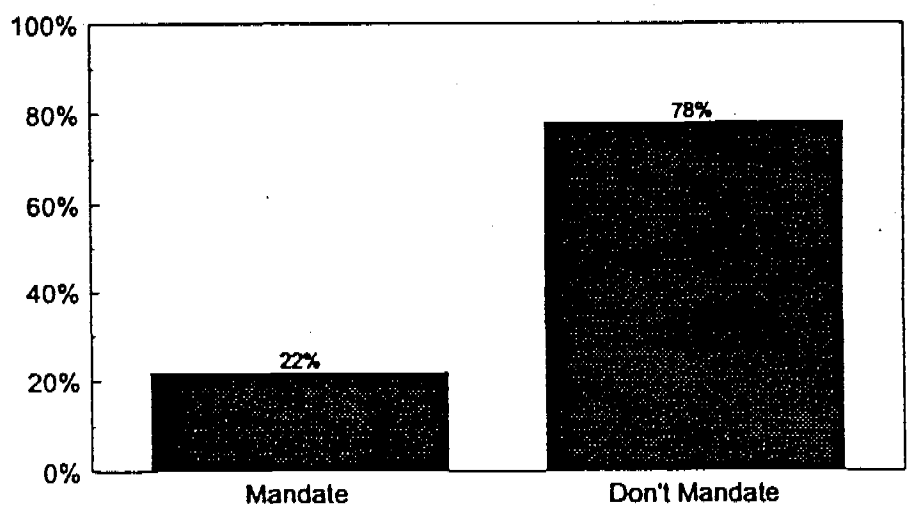
The following major survey findings are broken into two segments: 1) responses to questions applicable to utilities which offer <u>only voluntary</u> residential TOD rates, 2) responses to utilities which <u>mandate</u> TOD rates to a segment of the residential class (these utilities, in addition to mandatory participation, may also offer voluntary TOD rates to its residential class).

Percent of Utilities Offering TOD Rates



92 Utilities Responding

Of the Utilities Offering TOD Rates, Percent that Mandate Participation to a Segment

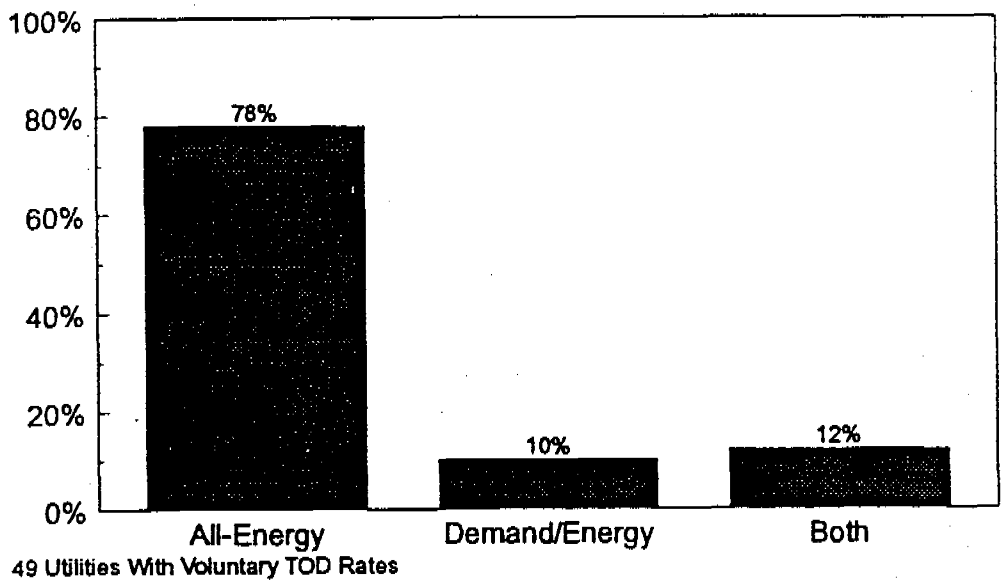


92 Utilities Responding

Responses from Utilities Which Offer Only Voluntary TOD Rates

The following responses are from the 49 utilities which offer only voluntary TOD rates.

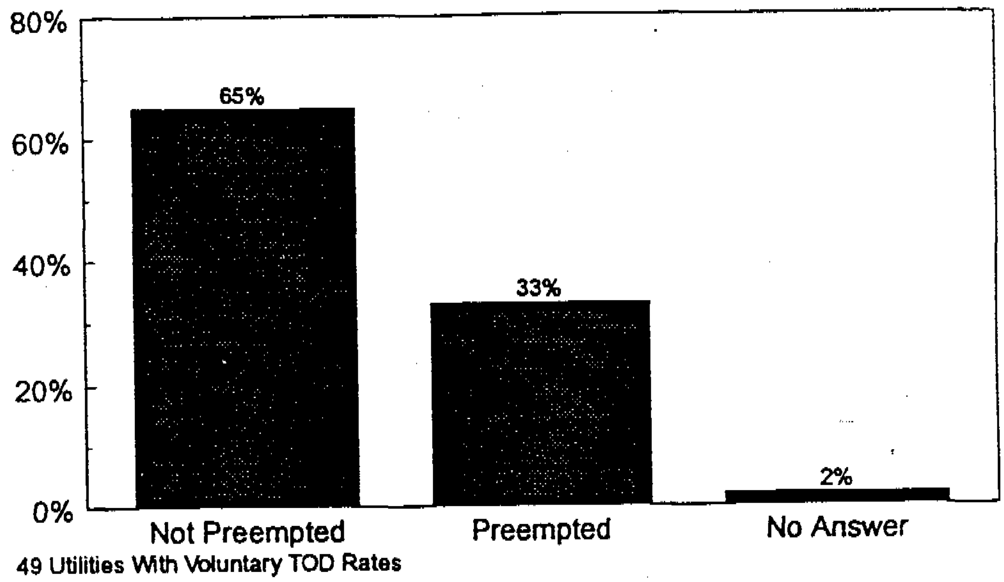
Of Utilities Offering Voluntary TOD Rates, Structure of Rates Offered



Utilities Which Offer Voluntary TOD Rates

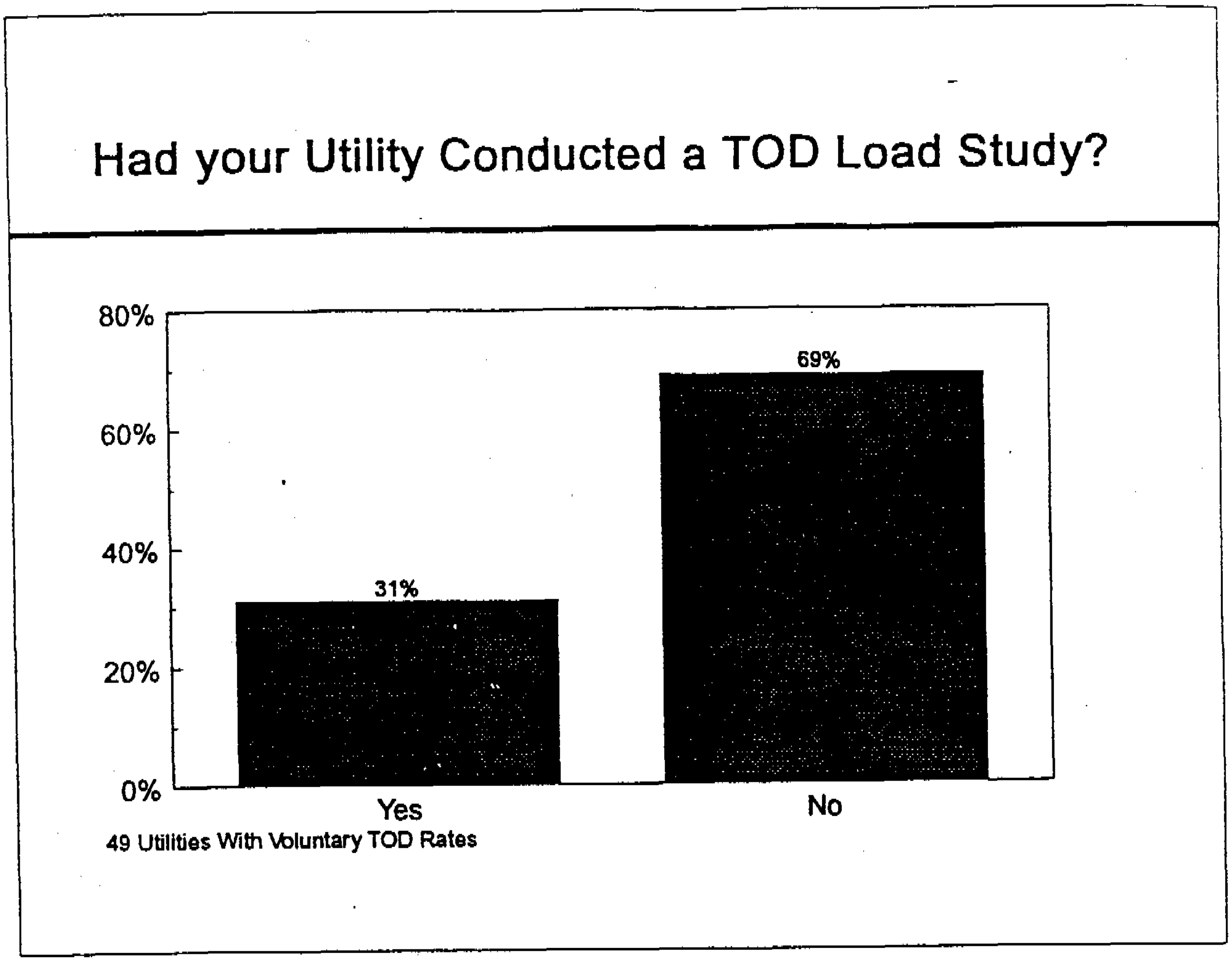
>> Thirty-eight (38) of the 49 utilities which offer voluntary rates, or 78%, design their TOD rates using an all-energy structure. Five (5) utilities, or 10%, use a demand/energy rate design, while 6 utilities (12%) offer both rate structures.

Have TOD Activities Been Preempted due to DSM Activities?



Utilities Which Offer Voluntary TOD Rates

>> Regarding whether or not their utility's TOD activities have been preempted by Demand-Side Management (DSM) activities, two-thirds indicated that DSM efforts have not preempted their TOD efforts, while one-third indicated that it had.



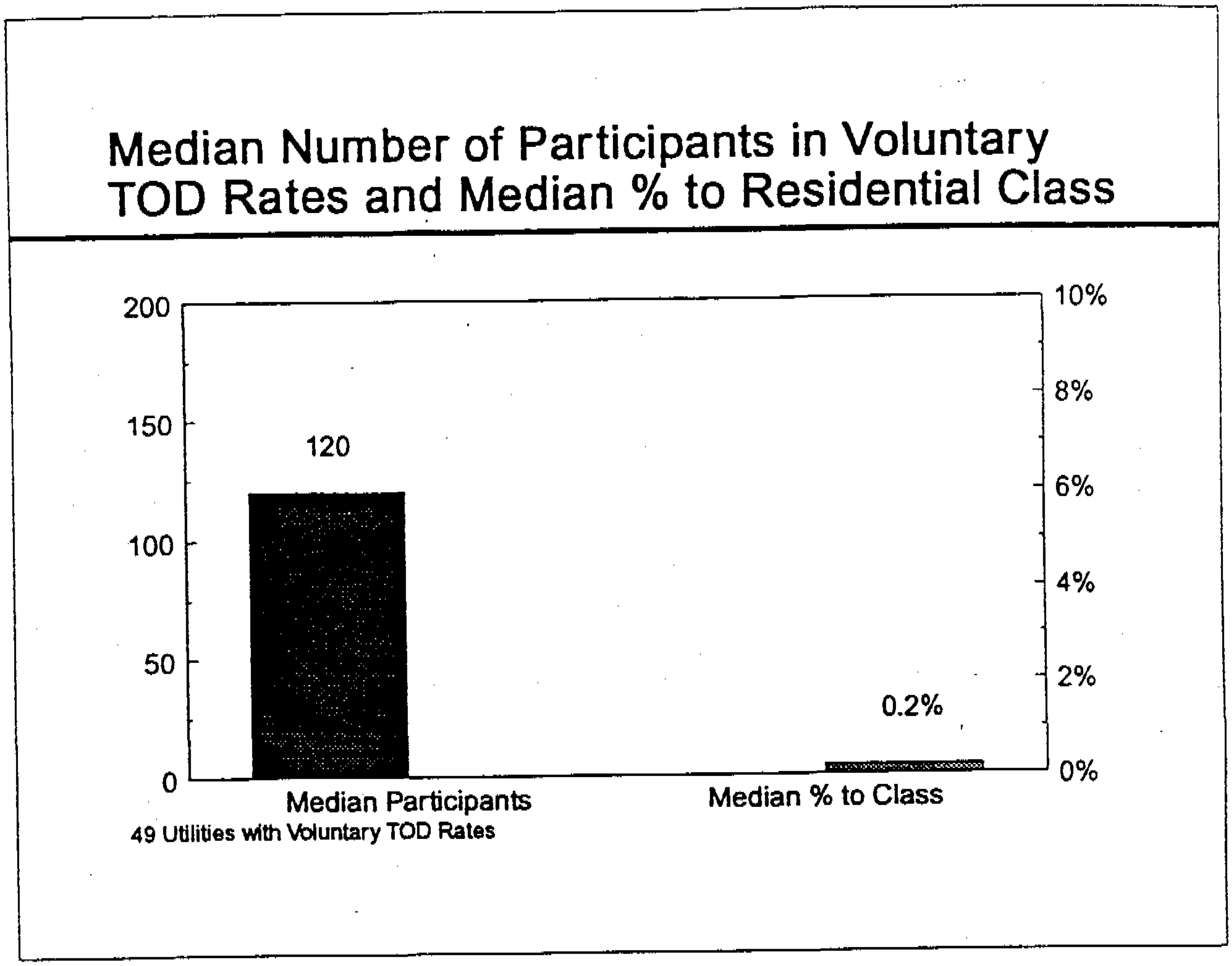
<u>Utilities Which Offer Voluntary TOD Rates</u>

\>> When asked whether they had conducted a load study:

Yes 31%

No 69%

The utilities were asked to provide significant findings of their load studies. The responses were generally mixed, with some utilities seeing load shifts and/or kWh impacts, while others did not measure any significant changes. Several utilities indicated that studies were being conducted now, but results were not available. It appears the most extensive study was conducted in the mid 1980's by a West Coast utility with a sample of 5000 customers (treatment, control, and non-volunteers) with pre-metering. This study did show reductions in on-peak usage and on-peak load for the TOD group.



Utilities Which Offer Voluntary TOD Rates

\>> The utilities were asked to provide the number of customers who were participating in their TOD rates, as well as the respective percentage of TOD customers to their total residential class. The following lists the utility median and average TOD participants (median is the more appropriate indicator of central tendency for this distribution):

TOD Rates Participation

Median utility participants: 120 customers

Median percent to total residential class: 0.2%

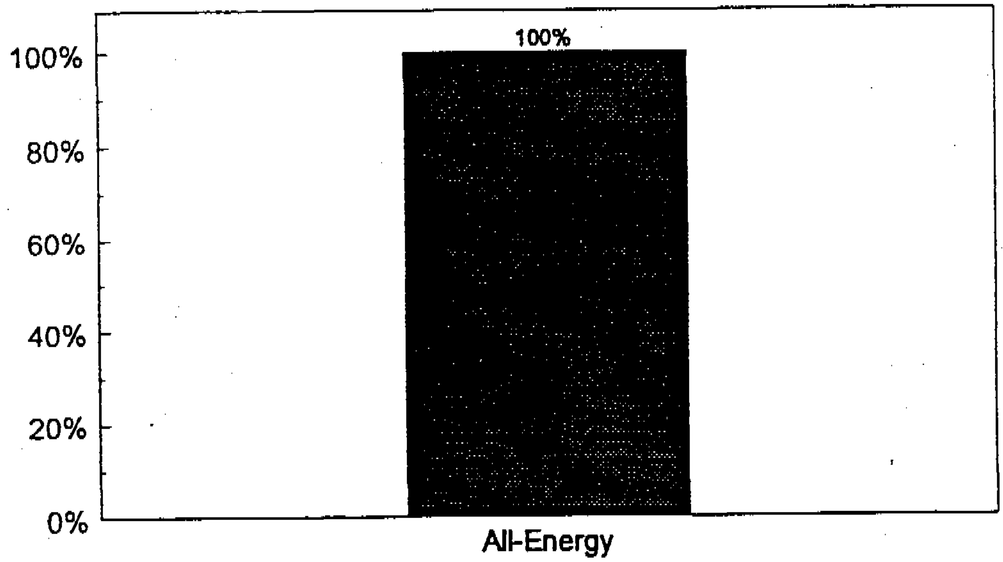
Average utility participants: 7,473 customers

Average percent to total residential class: 1.99%

Responses from Utilities Which Mandate TOD Rates to a Segment of its Residential Class (may also offer voluntary TOD rates to other segments)

The following responses are from the 14 utilities which mandate TOD rates to a segment of the class. Of the 14 utilities in this category, two utilities have only just implemented the rates within the past year. Accordingly, the responses from these two utilities have been excluded from those questions which require answers based on experience with mandatory TOD rates.

Of Utilities Mandating TOD Rates, Structure of Rates Offered

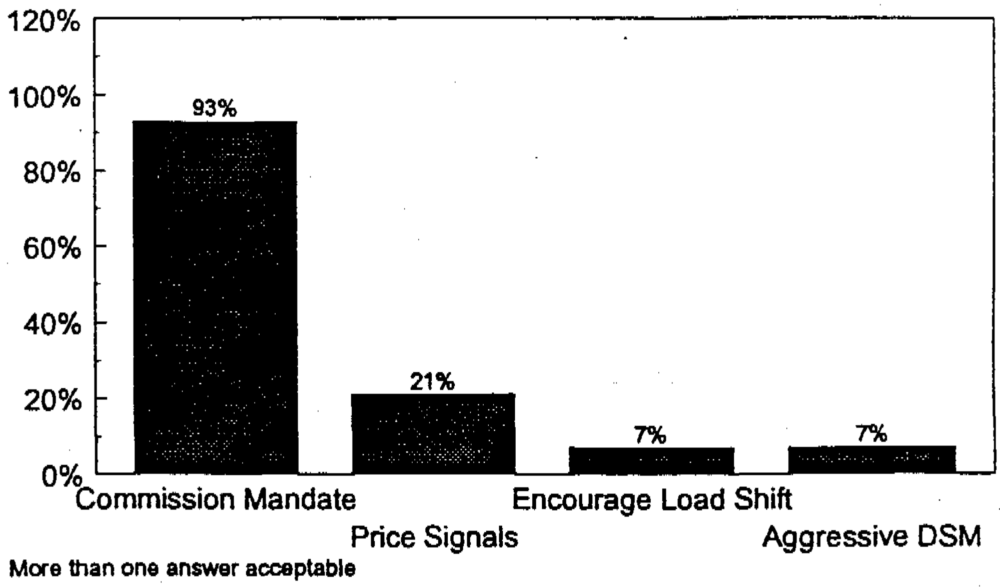


14 Utilities Mandating TOD Rates to a Residential Segment

<u>Utilities Which Mandate TOD Rates to a Segment of its Residential Class</u>

>> All 14 utilities' rates are designed using an all-energy structure.

Reasons for Implementation of Mandatory TOD

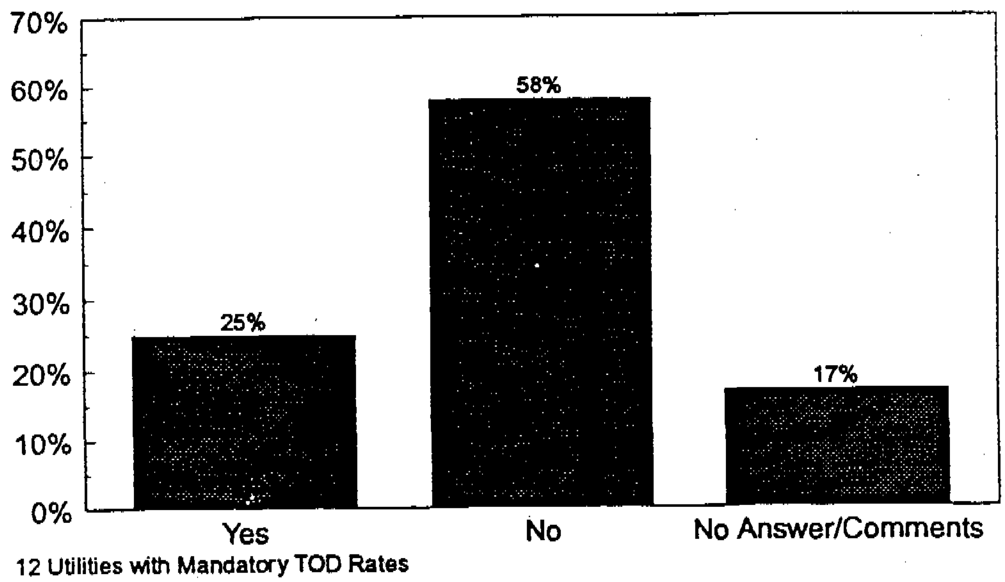


Utilities Which Mandate TOD Rates to a Segment of its Residential Class

\>\> Responses as to why their utility has implemented mandatory TOD rates (may have more than one answer):

Commission mandate	93%
Price signal	21%
Encourage load shift	7%
Aggressive DSM	7%

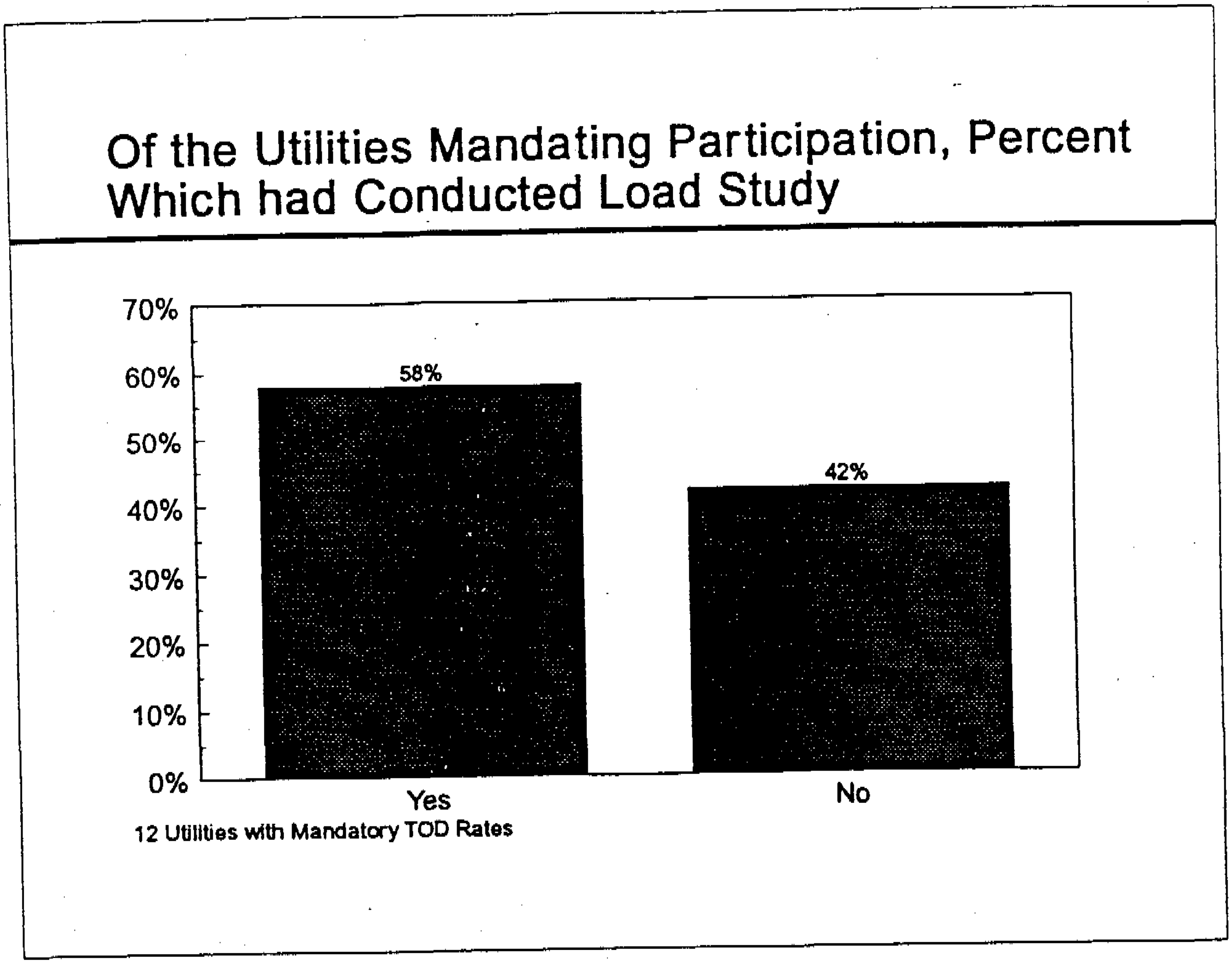
Would Utility Recommend Mandatory TOD Rates based on their Experience?



<u>Utilities Which Mandate TOD Rates to a Segment of its Residential Class</u>

>> When asked whether or not they would recommend mandatory TOD rates, given their experience:

Yes	25%
No	58%
No answer or provided comments in lieu of a yes/no answer	17%



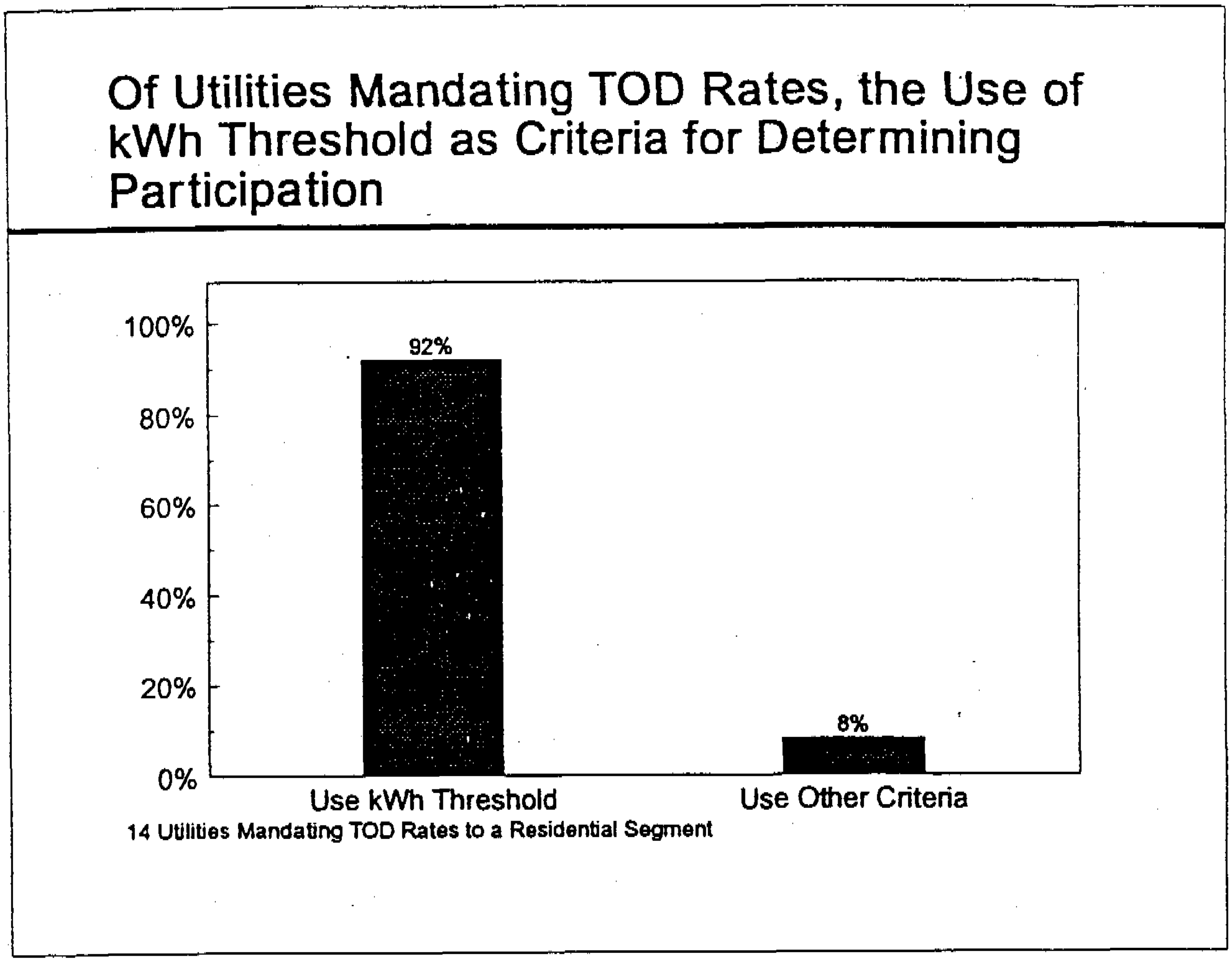
<u>Utilities Which Mandate TOD Rates to a Segment of its Residential Class</u>

>> When asked whether they had conducted a load study:

Yes 42%

No 58%

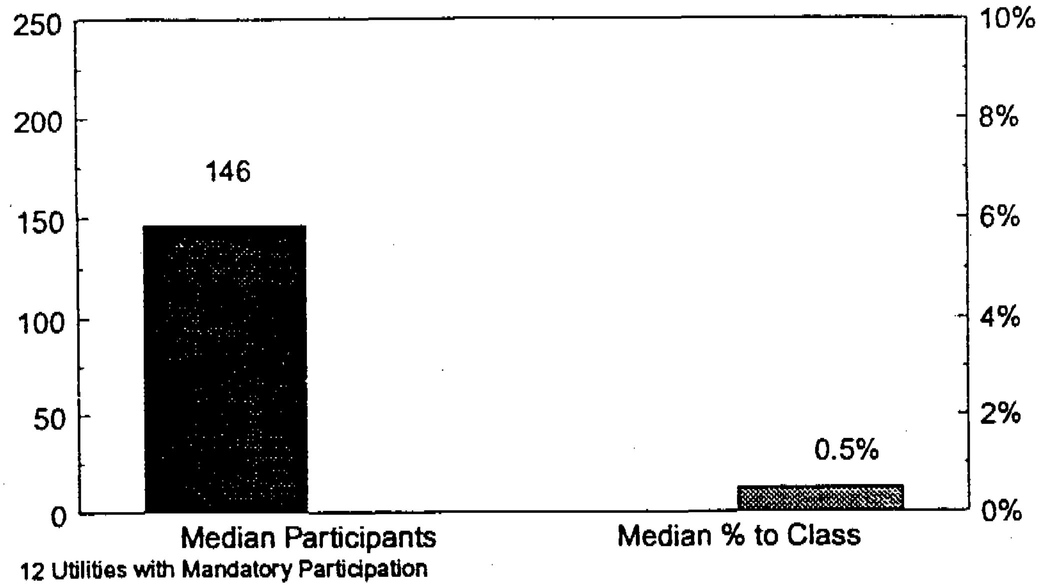
The utilities were asked to provide significant findings of their load studies. The responses were generally mixed, with two utilities seeing some load shifts, and three utilities not measuring any significant shifts. One service company had mandatory TOD rates in two of its operating utilities, and found load shifting in one of its subsidiaries, but not the other. Oddly enough, the on-peak to off-peak ratio was less for the subsidiary which observed load shifting compared to the subsidiary which did not observe any shifts.



Utilities Which Mandate TOD Rates to a Segment of its Residential Class

>> Ninety-two percent of the utilities utilize a kWh threshold as a determining criteria for mandatory participation. The threshold is applied to a variety of periods. Forty-six percent of the utilities use annual usage. Other periods include: summer month (one occurrence), winter month (3 occurrences), and total usage over summer season (3 occurrences). One utility does not use kWh usage as the criteria, but rather new, single family homes initially connected after January 1991 which have central heat or A/C.

Median Number of Participants in Mandatory TOD Rates and Median % to Residential Class for Utilities requiring Mandatory Participation



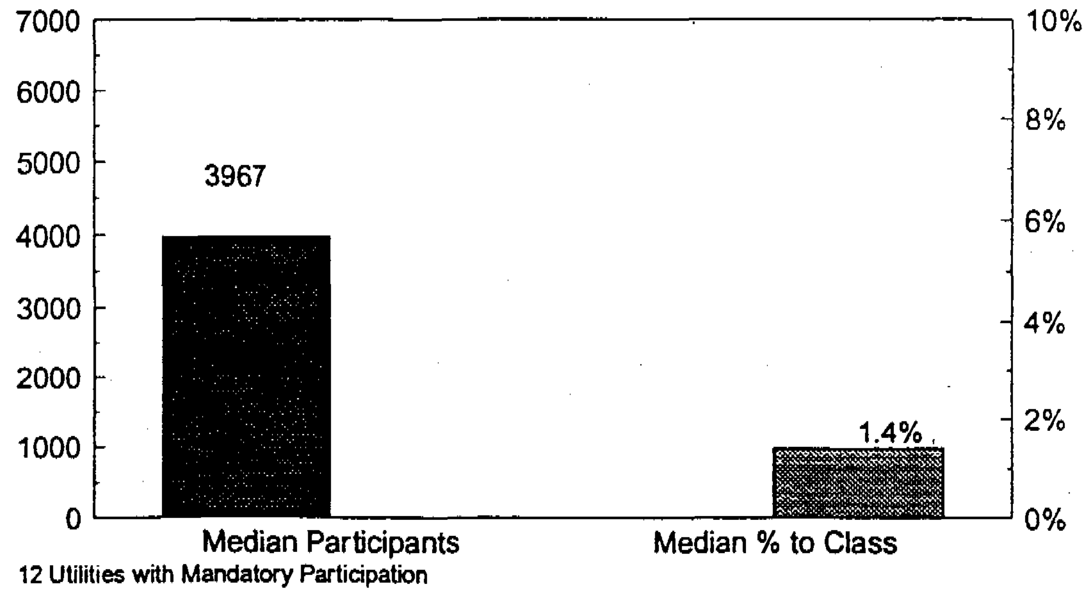
<u>Utilities Which Mandate TOD Rates to a Segment of its Residential Class</u>

>> The utilities were asked to provide the number of customers who were participating in their TOD rates, as well as the respective percentage of TOD customers to their total residential class. The following lists the utility median and average <u>mandatory only</u> TOD participants (median is the more appropriate indicator of central tendency for this distribution):

<u>Mandatory Only TOD Rates Participation</u>

Median utility participants: 146 customers
Median percent to total residential class: 0.5%
Average utility participants: 5,748 customers
Average percent to total residential class: 1.0%

Median Number of Participants in Mandatory and Voluntary TOD Rates and Median % to Residential Class for Utilities requiring Mandatory Participation



<u>Utilities Which Mandate TOD Rates to a Segment of its Residential Class</u>

>> The utilities were asked to provide the number of customers who were participating in their TOD rates, as well as the respective percentage of TOD customers to their total residential class. The following lists the utility median and average <u>total</u> TOD participants **(both voluntary and mandatory)** (**median** is the more appropriate indicator of central tendency for this distribution):

<u>Total TOD Rates (voluntary and mandatory) Participation</u>
Median utility participants: 3,967 customers
Median percent to total residential class: 1.4%
Average utility participants: 11,452 customers
Average percent to total residential class: 2.4%

APPENDIX F

REVIEW OF INNOVATIVE RATES

REVIEW OF INNOVATIVE RATES

1.0 EPRI Industry Survey on Types of Innovative Rates

In 1991, the Electric Power Research Institute ("EPRI") completed a comprehensive survey of innovative rates offered by utilities in the United States. Pages 2-2 and 2-3 of the EPRI Survey which identify and define each individual rate are included in this Appendix. A summary of the potential for the implementation of these rates by Newfoundland Power is also included in Table 1. There are hundreds of these rates, but they can be categorized into the following four categories:

1. Demand-Side Management Rates - These rates encourage customers to change their consumption patterns to encourage more efficient utilization of the electrical system.

2. Market Driven Rates - These are rates primarily based on responses to market prices of other goods and services.

3. Special-Needs Rates - These are rates designed to meet the specialized need of some customers.

4. Technology Specific Rates - These are rates designed for a specific technology. The unique load characteristics of the technology are used to design a rate.

2.0 Potential Innovative Rates for Newfoundland Power

A preliminary review was conducted of each of the four categories of innovative rates in the EPRI Survey.

2.1 Demand-Side Management Rates

Demand-side management (DSM) rates encourage customers to change their usage patterns. Conservation rates are not offered by Newfoundland Power but we do provide rebates to customers for energy efficient items such as insulation. Time-of-use rates offer a more practical solution than conservation rates and residential demand rates. Like most utilities, Newfoundland Power already offers a curtailable rate. We also have a direct load control pilot project in place for hot water heaters, whereby the customers are given a fixed $20 credit per year for participating. Since there is no significant variation in the marginal energy costs on the Island Interconnected System, real-time rates would not benefit customers. Surplus power rates are not practical for Newfoundland Power since it is a distribution utility with no surplus generation. Residential demand/energy rates are not easily understood by residential customers.

2.2 Market-Driven Rates

Many of the market-driven rates may not be acceptable in the legal and regulatory framework in Newfoundland. Economic development rates usually involve subsidies to customers to attract them to the utility's service territory, and therefore are difficult to justify in the current regulatory framework. Indexed rates and fixed term contract rates are generally offered only for large industrial customers. However, Newfoundland Power feels that it needs to become more flexible in responding to the marketplace. In this regard, load retention rates would be acceptable, and should be offered by Newfoundland Power if the loss of such a customer load would result in higher overall rates to other customers.

2.3 Special Needs Rates

Some of the special needs rates may be suitable for certain Newfoundland Power customers. Rates that do not violate sound rate making principles and do not involve significant cross subsidization are worth further consideration. Low income residential rates would not qualify since they involve subsidizing on the basis of ability to pay. Accordingly, special needs rates such as stand-by rates, and buy-back rates, which don't raise significant cross subsidization issues, are worth further consideration if the customer need arises.

2.4 Technology-Specific Rates

Time-of-use rates are, in many ways, superior to all of the technology specific rates and largely eliminate the need for such rates. Time-of-use rates are more practical since they eliminate the need to police customers to confirm that they have the end-uses for which the rate is designed. The disadvantage of a time-of-use rate is that it requires the additional cost of a time-of-use meter. Dual-fuel rates, whereby a customer has two heating sources and switches over to the alternate heating source from electric heat when the temperature goes below a trigger point, have had some success for Hydro-Quebec. Dual-fuel rates require a significant investment on behalf of customers. Time-of-use rates (including time-of-day and seasonal rates) are more attractive since only the time-of-use meter is required for the time-of-day rate and no investment is required for the seasonal rate.

2.5 Summary of Review of Potential Rates

A properly designed time-of-use rate which reflects marginal costs is superior to the technology specific and other special use rates. Time-of-use rates will accomplish the same goals as these other innovative rates without having to target specific end uses. Specifically, time-of-day rates and seasonal rates offer the greatest potential to the largest number of customers. Time-of-day rates and seasonal rates were designed for each rate class in this report.

Other rates worthy of further consideration include buy-back rates, load retention rates, and stand-by rates. Buy-back rates are where the utility pays customers for power supplied by the customer (i.e., a purchased power rate). Standby rates are for the provision of standby power to customers that have their own generation. Load retention rates encourage the deferral of customer's plans to install their own generation if the loss of such a customer load would result in higher overall rates to customers. These rates have not been designed as part of this study but may be desirable in the future if the customer need arises. Newfoundland Power can use the results of the marginal cost study in this report to design other rates as required.

Table 1
Summary Of Potential Innovative Rates for Newfoundland Power

Rate Option	Description	Newfoundland Power
1. **Demand Side Management Rates**		
Conservation Rates	encourage insulation etc.	already offer rebates
Interruptible/Curtailable rates	customer curtails their load	already have a rate
Load Control Rates	controlling individual loads such as hot water tanks	have a pilot project in place
Real -Time Rates	price set hourly based on actual cost	not attractive to customers based on energy price
Time-of-Day Rates		designed in this report
Seasonal Rates		designed in this report
Residential Demand Rates		not acceptable to customers
Surplus Power Rates	off-peak surplus energy is sold at lower prices	not necessary at this time
2. **Market- Driven Rates**		
Economic Development Rates	discounted rates are offered to attract new industrial customers	not acceptable
Fixed Term Contract	rates "locked-in" for contract period	may not be acceptable as a retail rate
Indexed Rates	variable rates tied to index	may not be acceptable as a retail rate
Load Retention Rates		future potential
3. **Special Needs Rates**		
Buy-back Rates	purchases surplus power from customer	future potential
Low-Income Residential Rates	discounted rate based on income	not acceptable
Prepaid Electric Service	prepaid metering	not a rate per se
Stand-by rates	utility backs up customer generation	future potential
4. **Technology Specific Rates**		TOU rates are a better alternative at this time
Electric Vehicle Rates		
Heat Pump Rates		
Storage Water Heating Rates		
Solar Energy Rates		
Thermal Storage Rates		
Misc. Technology-Specific Rates		
Dual-Fuel Rates	customer switches to an alternate heating system when temperature drops below a set point	may have potential but TOU is a better alternative at this time

1. Demand-Side Management Rates

Demand-side management (DSM) rates encourage customers to change their usage patterns. These rates may be part of an ongoing DSM program or they may be used independently. The following is a list of rate types fitting this description.

- Conservation Rates:
  - Incentives for implementing specific insulation guidelines or for use of specific energy conservation devices.
- Interruptible and Curtailable Rates:
  - Demand credits or lower demand charges given in exchange for complete demand reduction (interruptible) or reduction to a pre-determined level (curtailable) upon utility notice.
- Load Control Rates:
  - Incentives for allowing the utility to physically control various end-use appliances or equipment.
- Real-Time Rates:
  - Rates which are only applicable for short periods of time and whose price levels are set for weeks, days, or hours prior to use.
- Residential Demand Rates:
  - Rates requiring residential customers to pay for their demand on the system as well as the energy they use.
- Residential Time-of-Use Rates:
  - Residential rates based on energy consumption that varies with the time of day.
- Surplus Rates:
  - Greatly reduced rates for surplus power that is used only at such times as power is available.

2. Market-Driven Rates

Rates based primarily on economic conditions that are outside the utility's control are categorized as market-driven. These rates operate to enhance market conditions for the customer, the utility, or the region.

- Economic Development Rates:
  - Discounted rates offered to new or existing industrial customers in order to revitalize economically-depressed areas.
- Fixed-Term Rate Contracts:
  - Rates "locked-in" for the duration of a specified contract period, typically for large industrial users.
- Indexed Rates:
  - Variable rates specifically tied to the Consumer Price Index, the price of the customer's product, overall fuel costs, or other economic factors.

- Regional Rate Options:
  - Rates based on an average of all regional utilities' rates to large industrial users.
- Emerging Rates:
  - Rates that are market-driven but do not fit into any of the above-stated categories.

3. Special-Needs Rates

These rates serve needs not addressed by otherwise available rate options. Rates designed to satisfy specific customer requirements have been placed in this category.

- Buy-Back Rates:
  - Rates in which utility pays customer for power supplied by the customer.
- Load-Retention Incentive Rates:
  - Rates that encourage a deferral of customer's plans to install on-site generation, or that discourage use of already existing on-site generation.
- Low-Income Residential Rates:
  - Rates that provide low-income customers an allotment of base power use at a subsidized price.
- Prepaid Electric Service:
  - Rates that are discounted to customers that prepay for their service in large dollar amounts.
  - Rates on which customers purchase magnetically-encoded cards that operate home meters, allowing the customer to use a predetermined amount of electricity each month.
- Stand-By Rates:
  - Rates for the provision of standby power to customers that have their own on-site power source; in return the customer pays a rate which is intended to represent the real cost of the service.

4. Technology-Specific Rates

Technology-specific rates are available only to customers who use a designated end-use technology. Although the technology specified may also qualify a rate as a demand-side management rate or a market-driven rate, the following rates will be categorized as technology-specific for the purposes of this report:

- Electric Vehicle Rates;
- Heat Pump Rates;
- Storage Water Heating Rates;
- Solar Energy Rates;
- Thermal or Ice Storage Rates; and
- Miscellaneous Technology-Specific Rates.

APPENDIX G

RATE DESIGN REVENUE RECONCILIATIONS

TABLE OF CONTENTS

Rate Design Revenue Reconciliations

Summary

Rate Class	Standard Rates	Time of Day Rates	Seasonal Rates
Rate 1.1 Domestic	$ 205,394,629	$ 205,394,535	$ 205,395,929
General Service			
Rate 2.1 G.S. 0-10 kW	$ 10,090,343	$ 9,991,898	$ 9,991,898
Rate 2.2 G.S. 10-100 kW	$ 46,057,343	$ 44,700,466	$ 44,724,078
Rate 2.3 G.S. 110 kVA-1000 kVA	$ 50,963,166	$ 51,027,220	$ 51,023,844
Rate 2.4 G.S. 1000 kVA and Over	$ 17,286,135	$ 18,666,960	$ 18,655,402
Total General Service	$ 124,396,988	$ 124,386,544	$ 124,395,222

Basis for Calculations:

1. The 1997 energy forecast that was accepted as reasonable by the Board in Order No. P.U. 7 (1996-97) was used in the revenue calculations. The forecast billing determinants for the Hibernia Bull Arm facility were excluded in estimating the revenue from Rate 2.4.

2. The rates effective April 1, 1997 and approved by the Board in Order No. P.U. 14 (1996-97) were used in the calculations of revenue from standard rates (i.e., existing rates excluding Rate Stabilization and Municipal Tax adjustments).

3. Forfeited prompt payment discounts and transformer ownership credits were excluded in performing the revenue reconciliations. We assumed the amounts of these adjustments would be the same for the standard, time of day, and seasonal rates.

4. The on-peak and off-peak energy usage was estimated from data gathered through the Company's load research program. The on-peak demands were assumed to equal the winter season monthly billing demands.

Domestic Revenue Reconciliation

Standard Rate

	Units		Price		Revenue
Number of Customer Monthly Bills in 1997	2,169,107	$	16.16	$	35,052,769
Energy Usage (kWh)	2,653,300,000		0.06420	$	170,341,860
Total				$	205,394,629

Time of Use Rate

	Units		Price		Revenue
Number of Customer Monthly Bills in 1997	2,169,107	$	16.16	$	35,052,769
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	835,370,400		0.10990	$	91,807,207
Off-Peak kWh	1,817,929,600		0.04320	$	78,534,559
Total				$	205,394,535

Seasonal Rate

	Units		Price		Revenue
Number of Customer Monthly Bills in 1997	2,169,107	$	16.16	$	35,052,769
Winter Season kWh	1,215,500,000		0.08916	$	108,373,980
Non-Winter Season kWh	1,437,800,000		0.04310	$	61,969,180
Total				$	205,395,929

General Service Revenue Reconciliation - Standard Rates

Rate 2.1		Units		Price		Revenue
Number of Customer Monthly Bills in 1997		128,830	$	18.39	$	2,369,184
Energy Usage (kWh)		89,816,641		0.08444	$	7,584,117
Three Phase Minimum Monthly Charge		3,726		36.78	$	137,042
Total					$	10,090,343

Rate 2.2		Units		Price		Revenue
Number of Customer Monthly Bills in 1997		91,856	$	19.80	$	1,818,749
Winter Billing Demand (kW)		721,469		7.55	$	5,447,091
Non-Winter Billing Demand (kW)		1,106,459		6.82	$	7,546,050
Energy Charges	First 150/kWh/kW	273,441,793		0.06738	$	18,424,508
	Excess	254,328,275		0.04110	$	10,452,892
Maximum Monthly Charge (kWh)		15,239,932		0.139	$	2,118,351
Minimum Monthly Charge $/kW		101,896		2.33	$	237,418
Three Phase Minimum Monthly Charge		334		36.78	$	12,285
Total					$	46,057,343

Rate 2.3		Units		Price		Revenue
Number of Customer Monthly Bills in 1997		10,860	$	89.11	$	967,735
Winter Billing Demand (kVA)		816,766		6.56	$	5,357,985
Non-Winter Billing Demand (kVA)		1,334,652		5.83	$	7,781,021
Energy Charges	First 150/kWh/kVA (Max. 30,000)	226,669,688		0.06412	$	14,534,060
	Excess	513,641,023		0.04006	$	20,576,459
Maximum Monthly Charge (kWh)		11,136,325		0.139	$	1,547,949
Minimum Monthly Charge $/kW		84,960		2.33	$	197,957
					$	50,963,166

Rate 2.4		Units		Price		Revenue
Number of Customer Monthly Bills in 1997		448	$	178.22	$	79,843
Winter Billing Demand (kVA)		261,945		6.28	$	1,645,015
Non-Winter Billing Demand (kVA)		531,702		5.55	$	2,950,946
Energy	First 100,000 kWh	44,800,000		0.05264	$	2,358,272
	Excess	262,000,000		0.03913	$	10,252,060
					$	17,286,135

Total Revenue From Standard General Service Rates	**$ 124,396,988**

General Service Revenue Reconciliation - Time of Day Rates

	Units		Price		Revenue
Rate 2.1					
Number of Customer Monthly Bills in 1997	128,830	$	25.00	$	3,220,750
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	24,193,046		0.16270	$	3,936,209
Off-Peak kWh	65,623,595		0.04320	$	2,834,939
Total Rate 2.1				$	9,991,898

	Units		Price		Revenue
Rate 2.2					
Number of Customer Monthly Bills in 1997	91,856	$	41.00	$	3,766,096
Rate 2.2 - Secondary					
On-Peak Billing Demand (kW)	718,964		23.52	$	16,910,033
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	145,757,542		0.04670	$	6,806,877
Off-Peak kWh	395,367,082		0.04320	$	17,079,858
Rate 2.2 - Primary					
On-Peak Billing Demand (kW)	2,505		22.39	$	56,087
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	507,846		0.04550	$	23,107
Off-Peak kWh	1,377,530		0.04240	$	58,407
Total Rate 2.2				$	44,700,466

	Units		Price		Revenue
Rate 2.3					
Number of Customer Monthly Bills in 1997	10,860	$	89.11	$	967,735
Rate 2.3 - Secondary					
On-Peak Billing Demand (kVA)	676,906		21.17	$	14,330,100
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	126,303,883		0.04670	$	5,898,391
Off-Peak kWh	342,599,067		0.04320	$	14,800,280
Rate 2.3 - Primary					
On-Peak Billing Demand (kVA)	138,942		20.15		2,799,681
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	75,498,956		0.04550	$	3,435,202
Off-Peak kWh	204,790,788		0.04240	$	8,683,129
Rate 2.3 - Transmission					
On-Peak Billing Demand (kVA)	918		18.89	$	17,342
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	607,230		0.04420	$	26,840
Off-Peak kWh	1,647,111		0.04160	$	68,520
Total Rate 2.3				$	51,027,220

General Service Revenue Reconciliation - Time of Day Rates

	Units		Price		Revenue
Rate 2.4					
Number of Customer Monthly Bills in 1997	448	$	178.22	$	79,843
Rate 2.4 - Secondary					
On-Peak Billing Demand (kVA)	20,437		21.17	$	432,651
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	18,455,747		0.04670	$	861,883
Off-Peak kWh	59,471,453		0.04320	$	2,569,167
Rate 2.4 - Primary					
On-Peak Billing Demand (kVA)	237,708		20.15	$	4,789,816
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	51,516,238		0.04550	$	2,343,989
Off-Peak kWh	166,004,962		0.04240	$	7,038,610
Rate 2.4 - Transmission					
On-Peak Billing Demand (kVA)	3,800		18.89	$	71,784
On-Peak kWh (7 AM to 10 PM Weekdays) (9 AM to 10 PM Weekends)	2,688,436		0.04420	$	118,829
Off-Peak kWh	8,663,164		0.04160	$	360,388
Total Rate 2.4				$	18,666,960
Total Revenue From Time of Day General Service Rates				**$**	**124,386,544**

General Service Revenue Reconciliation - Seasonal Rates

	Units		Price		Revenue
Rate 2.1					
Number of Customer Monthly Bills in 1997	128,830	$	25.00	$	3,220,750
Winter Season (kWh)	36,924,619		0.12164	$	4,491,502
Non-Winter Season (kWh)	52,892,022		0.04310	$	2,279,646
Total Rate 2.1				$	9,991,898
Rate 2.2	Units		Price		Revenue
Number of Customer Monthly Bills in 1997	91,856	$	41.00	$	3,766,096
Rate 2.2 - Secondary					
Winter Season Billing Demand (kW)	718,964		23.58	$	16,953,171
Winter Season (kWh)	226,922,314		0.04550	$	10,324,965
Non-Winter Season (kWh)	314,202,310		0.04310	$	13,542,120
Rate 2.2 - Primary					
Winter Season Billing Demand (kW)	2,505		22.45	$	56,235
Winter Season (kWh)	790,638		0.04450	$	35,183
Non-Winter Season (kWh)	1,094,737		0.04230	$	46,307
Total Rate 2.2				$	44,724,078
Rate 2.3	Units		Price		Revenue
Number of Customer Monthly Bills in 1997	10,860	$	89.11	$	967,735
Rate 2.3 - Secondary					
Winter Season Billing Demand (kVA)	676,906		21.22	$	14,363,945
Winter Season (kWh)	190,263,122		0.04550	$	8,656,972
Non-Winter Season (kWh)	278,639,829		0.04310	$	12,009,377
Rate 2.3 - Primary					
Winter Season Billing Demand (kVA)	138,942		20.20		2,806,628
Winter Season (kWh)	113,731,001		0.04450	$	5,061,030
Non-Winter Season (kWh)	166,558,744		0.04230	$	7,045,435
Rate 2.3 - Transmission					
Winter Season Billing Demand (kVA)	918		18.94	$	17,387
Winter Season (kWh)	914,727		0.04330	$	39,608
Non-Winter Season (kWh)	1,339,615		0.04160	$	55,728
Total Rate 2.3				$	51,023,844

General Service Revenue Reconciliation - Seasonal Rates

	Units		Price		Revenue
Rate 2.4					
umber of Customer Monthly Bills in 1997	448	$	178.22	$	79.843
Rate 2.4 - Secondary					
Winter Season Billing Demand (kVA)	20,437		21.22	$	433,673
Winter Season (kWh)	26,873,200		0.04550	$	1,222,731
Non-Winter Season (kWh)	51,054,000		0.04310	$	2.200,427
Rate 2.4 - Primary					
Winter Season Billing Demand (kVA)	237,708		20.20	$	4,801.702
Winter Season (kWh)	75,012,200		0.04450	$	3,338,043
Non-Winter Season (kWh)	142,509,000		0.04230	$	6,028,131
Rate 2.4 - Transmission					
Winter Season Billing Demand (kVA)	3,800		18.94	$	71,972
Winter Season (kWh)	3,914,600		0.04330	$	169,502
Non-Winter Season (kWh)	7,437,000		0.04160	$	309,379
Total Rate 2.4				$	18,655,402
Total Revenue From Seasonal General Service Rates				**$**	**124,395,222**

CARRYING CHARGE COST ASSOCIATED WITH A NEW TIME-OF-DAY METER
Based on Annualizing Capital Expenditures using the Economic Carry Charge Method

MARGINAL COST OF METERS

a	Investment Difference between TOD meter and non-TOD meter	180.0	$/Meter
b	Increm. Capitalized Gen. Expense (c X 9.6%)	17.3	$/Meter
c	General Plant Loading (a X 12.5%)	22.5	$/Meter
d	**Total Marginal Investment Cost**	**219.8**	**$/Meter**
e	Annualization Factor	12.14%	
f	Plant Related Gen. Exp. Loading	0.27%	
	Annualized Cost of Capital Additions	**27.3**	**$/Meter**
	Working Capital		
j	Materials and Supplies (d X 0.46%)	1.01	$/Meter
k	Prepayments (d X 0.28%)	0.62	$/Meter
m	Revenue Req'd for Working Capital ((j+k+m) X 13.02%)	0.21	$/Meter
	Total Marginal Working Capital	**0.2**	**$/Meter**
	TOTAL CARRYING CHARGE PER YEAR	**27.5**	**$/Meter**
	TOTAL CARRYING CHARGE PER MONTH	**2.29**	**$/Meter**
	Time-of-Day Rate Metering Surcharge per month	**2.25**	**$/Meter**