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FACSIMILE TRANSMISSION

TO: Newfoundland and Labrador Hydro

Attention: Maureen Greene, Q.C.

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FROM: Dennis Browne, Q.C.

DATE: November 17, 2003

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November 17, 2003

Via Courier

Board of Commissioners of Public Utilities
120 Torbay Road P.O. Box 21040
St. John's, Newfoundland
A1A 5B2

Attention: Cheryl Blundon

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2003 General Rate Application

Further to the above captioned and pursuant to the Procedural Order governing these proceedings, we are enclosing ten (10) copies of IC#7 and IC#8 from the 2001 Hydro GRA, which documents the Consumer Advocate may rely upon during cross-examination of Newfoundland Power's Cost of Service expert.

Yours truly,

Stephen Fitzgerald
Counsel for the Consumer Advocate

SF/bh
Encl.

cc NF & Labrador Hydro
Attention: Maureen Greene, Q.C.

cc Newfoundland Power Inc.
Attention: Peter Alteen / Ian Kelly, Q.C.

cc Stewart McKelvey Stirling Scales
Attention: Janet Henley-Andrews

cc Poole Althouse
Attention: Joseph S. Hutchings

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cc Miller & Hearn
Attention: Edward Hearn, Q.C.

cc Law Atlantic
Attention: Mark Kennedy, Board Counsel

Brookman 1990 pages 13 - 17 & 19/20

IC#7

COST OF SERVICE STUDY

Q. Do you have any comments on the cost of service study submitted by Hydro in this proceeding?

A. While PDD's customers have been absorbed into Hydro's system, Hydro chose not to show them as a customer in the cost of service study. The generally accepted practice in the case where a customer class is to be excluded from the cost of service is to perform a separation study to show that the costs and revenues are being properly excluded from the remaining system.

A separation study is simply a cost of service study which shows in a logical and understandable manner how the total costs and revenues of the utility are split up. In the U.S., ~~the~~ studies are important to ensure that the regulated portions of the utility are not being asked unfairly to pick up costs not rationally attributable to them. In the case of NLP, such a study is important even though NLP and the industrials will be asked to pay any difference between the cost of serving Hydro's rural customers and the revenues gathered from them, because without such a study it is impossible to properly review those costs. Surely Hydro's other customers who are being asked to pay a hidden subsidy in their rates have a right to know how that subsidy was determined.

PROPOSED RATE STRUCTURE

Q. Do you have any concerns about the rate structure proposed by Hydro in this proceeding?

A. Yes. Hydro proposes to continue its practice of serving industrial customers with a rate containing both a demand and energy component, while offering an energy charge only rate to NLP. This is done in spite of the fact that the cost of service study contains sufficient information to provide a demand and energy rate structure to NLP.

As I previously touched upon, it is a well known principle of good ratemaking practice that costs imposed on an electric system are primarily functions of the three variables: number of customers, energy taken (kWh), and the demand (kW) imposed on the system. It is also widely accepted practice, consistent with the principle of ensuring rates reflect costs, to therefore signal these three costs separately in customer, energy and demand charges, where it is practical to do so.

NLP can impose any sort of load pattern on Hydro and, so long as the total energy use is the same under the various load patterns, the price NLP pays Hydro is the same until Hydro has a rate referral to propose a rate change. On an annual basis, a partial adjustment is made through the RSP.

This lack of proper rate design gives little incentive for NLP to engage in demand side management activities that reduce peak load. Peak load reduction programs are among the most common and cost effective demand side management programs in existence. With an energy only rate, however, there are no immediate savings to NLP and its customers for reducing its demand on the Hydro system. Because NLP applies demand charges to its large customers to control their demands, NLP will actually lose money if those customers respond properly.

Another fact that the Board should consider is the effect of the Hydro energy-only rate on NLP rates. It forces NLP to have energy rates that are too high and demand rates that are too low. If NLP is to achieve proper matching between the distinct cost causation effects of demand and energy, the Board should recommend that Hydro develop a rate structure that includes these important components.

Q. Could you outline any examples of alternative rate structures you feel might be more appropriate for Hydro to use in billing NLP?

A. Yes. While I am not proposing a specific rate for immediate implementation, I have outlined examples of two alternative rate structures that address this issue: a "Hopkinson" type of rate with an explicit demand and energy rate, and a "Wright" or hours-use-of-demand rate form.

Hydro currently uses the Hopkinson rate alternative in its rates to industrial customers. It consists of a monthly demand charge for each kilowatt-(kW)-of demand and uniform energy charge for all kilowatt-hours (kWh) of energy. A Hopkinson rate alternative for Hydro's service to NLP, based on data provided by Hydro, is as follows:

Demand Charge:	$7.17 per kW of demand per month
Energy Charge:	$0.0300 per kWh of energy consumed

The Hopkinson rate design differentiates between costs associated with capacity or demand in kW and those associated with the consumption of energy in kWh. The derivation of this rate, which is contained in Exhibit LBB-2 recovers much of Hydro's demand related cost in the demand charge.

Q. Please explain the Wright rate form.

A. The Wright rate uses the concept of hours-use-of-demand or load factor in pricing electric power service. Load factor is the ratio of the average load in kilowatts during a period divided by the maximum load during that period. Loads which occur at lower load factors pay a higher rate per kilowatt-hour. The Wright rate typically consists of a series of declining blocks with a specified number of kilowatt-hours per kilowatt of electric power included in each block. The Wright rate alternative for Hydro's service to NLP is as follows:

1st Block,	0 - 300 Hours Use of Demand	$0.05389 per kWh per kW
2nd Block,	Over 300 Hours Use of Demand	$0.03000 per kWh per kW

The Wright rate form was designed to recover much of Hydro's demand related, or capacity costs as well as a certain amount of running costs in the first block. This is sometimes called an implicit demand charge. The terminal block is designed to recover Hydro's running or energy costs.

Q. Will the Hopkinson or Wright rate form give NLP an incentive to make expenditures that will cause it and its customers to increase load factor, to lower demands imposed on Hydro's system, thus delaying future generating plants?

A. Yes. These rate forms encourage customers to lower their peak demands and spread their usage over a longer period of time, thereby improving the system load factor. Customers that maintain high load factors are able to spread demand charges over more kilowatt-hours and therefore achieve lower average costs.

Q. Did you design both rates to recover Hydro's revenue requirement during 1990?

A. Yes. Both rates were designed to recover the same revenue as Hydro's proposed energy-only rate for the full year 1990 (i.e. 45.31 mills). The rates are based on the estimates of a) Hydro's 1990 Cost of Service Study, b) the 1990 Revenue Requirement from NLP calculated using Hydro's proposed rate of 45.31 mills effective January 1, 1990, and c) the NLP loads that will be imposed on Hydro. Details of the calculations as well as a graph of the various alternatives are contained in LBB-2. Page 1 is a graphical representation of the average revenue from the two example rates and Hydro's proposed 1990 energy-only rate compared to the level of costs incurred at various load factors or hours use.

The primary difference between the two alternative rate structures is that the Hopkinson rate has an explicit demand charge whereas the Wright rate recovers most of the demand-related costs in the first energy block.

Q. Should the Board consider other criteria in establishing such a rate?

A. Yes. The Board should consider rate history when adopting a demand-energy rate structure for NLP. A radical departure from an established rate form might have an adverse consequence on the supplier and the customer. This concept of continuity is often referred to as "gradualism". The rate alternatives offered above do separate demand and energy costs but neither may be the best alternative. My recommendation would therefore be that Hydro work with NLP and develop a rate structure containing a demand component for implementation on July 1, 1991.

LEAST COST PLANNING

Q. Could you define the term demand side management?

A. Yes. Demand side management is generally defined as any attempt by the utility to influence customer use of electricity in ways that will produce desired changes in the controlling the supply side, how would the two be integrated?

Flexibility and risk are also important issues. A good least cost plan is able to respond well to charges in input assumptions, like fuel cost projections or changes in technology. One should not commit to any course of action which is only the best course if all assumptions hold true.

Presumably very little specific data on demand side management programs will be available. This raises the issue of how to balance the need for accurate study data with the need to act early to avoid building future power plants.

Another important consideration will be how to give utilities proper incentives to engage ~~in demand~~ side management, activities which ~~will decrease~~ their loads and revenues. Can the utilities put any demand management expenditures into rate base, or must they be expensed?

How to optimize the blend of supply and demand side options and how to recognize externalities, like environmental costs are difficult questions.

Obviously, to arrive at answers to such questions will require analysis, discussions and possibly generic public hearings.

SUMMARY

Q. Would you please summarize your testimony and recommendations?

A. Yes. I have enumerated several major principles of a sound regulatory framework. I have also attempted to show why Hydro's proposal in this proceeding violates several of our principles. I would recommend:

1. That Hydro's proposed guarantee of profits without full review for three years be rejected as violating the need to encourage efficiency of their operations. Instead, they should be limited to the 1990 test year at this time.

2. That Hydro's proposal to defer and then amortize over five years any difference between rates and costs be denied to the extent that such "losses" may be recovered from the balance in the RSP because this violates the principle of matching rates to costs, plus the RSP was established to stabilize rates.

3. That the Board consider seeking changes to the legislation that would either eliminate the requirement that NLP subsidize rural customers or that they be given more influence over the costs imputed as least cost to serve them, because such subsidies are unfair and inefficient.

4. That Hydro be required in the next rate case to file a cost of service study showing in full and proper detail the cost of serving all its customers because the parties to the case have a need and a right to such information.

5. That the Board encourage least cost planning procedures and filings from all the electric utilities it regulates to ensure efficiency of investment.

6. That the Board recommend that Hydro work with NLP and submit a rate structure that incorporates a demand component for implementation on July 1, 1991, because such a rate will better encourage proper demand side management and efficient operations by NLP's customers.

IC #8

preferential rates. I also agree that some gradualism should be adopted in their elimination.

I do have a concern, however, with one aspect of the gradualism Hydro is recommending here. That concern is that Hydro has provided no concrete plan of action for eliminating the subsidies. Given the magnitude of these subsidies and the fact that other customers are paying them directly, the absence of a concrete plan is not appropriate.

In response to Demand for Particulars NP-63, Hydro stated that they had no specific plan or time frame for elimination of the preferential rates, but that they fully expected it to be discussed at the hearing. It is my recommendation that the issue be discussed fully and that Hydro be required to develop and file with this Board a plan for elimination of these subsidies. This plan should be required within three months of the Board's final order in this case.

Q. **Do you agree with Hydro's proposal to adopt a three part NP rate with the energy charges set at marginal energy cost and the demand charge calculated as a residual?**

A. In concept, I do. The details may need some fine tuning, however. I think the proposed rate gives the movement to a demand/energy rate that NP argued was important in the last Hydro referral. In addition, energy is given a high weight in this rate design. It should enable NP to get a good balance of peak shaving and conservation oriented DSM programs.

pp 21-26
Brockman
direct
testimony
1992

Dr. Sarikas examined four different options with respect to the rate design ror NP. These options were: (i) continuation of the existing energy only rate form; (2) a three part demand, energy and customer charge rate with energy set at marginal cost and demand costs calculated as a residual; (3) a rate identical to (2) except demand charges in excess of forecast billing demand would be billed at avoided cost; and (4) a three part rate with energy set at marginal energy cost and an inverted demand rate with demand charges over 800 MW set at avoided demand cost. Hydro recommends option 2, at least initially, as a way to gain experience in its application.

Option 1, the energy only rate form, is what we now have. The problems with Option 1 were discussed extensively at the last hearing. An excellent summation of the arguments is contained on pages 76-79 of the Board's June 11, 1990 Report to Government. This rate form does not offer good tracking of costs because changes in energy cause certain costs to change and changes in demand cause others to change. This rate therefore does not offer good price signals to NP. In addition, NP offers some of its customers demand rates. If these customers respond to NP's price signal by reducing demand, NP loses revenues without a corresponding drop in demand related costs from Hydro. This same effect occurs with respect to peak shaving DSM equipment NP might wish to encourage its customers to install. For all these reasons, the Board recommended that Hydro submit at this hearing whatever information it might have with regard to a rate with a demand charge component. This is what Hydro has done here.

Options (2), (3) and (4) are really just variants of one another. All have the characteristic that the energy rate component is set at the marginal energy cost of Hydro, with total demand related cost being calculated as the residual between the revenue gathered from the marginal energy rate and customer charge minus the total revenue requirement allocated to NP. Options (2), (3), and (4) are all superior to an all-energy rate in signalling that both demand and energy have costs associated with them.

The clear intent of options 2-4 is to capture a strong marginal energy cost signal and send it to NP and its customers. This will enable them to make better evaluations of whether to increase or decrease consumption and to evaluate the benefits of investing in energy conservation measures. Unfortunately, one cannot usually set rates for demand and energy at marginal costs and still recover the allowed amount of revenue. This is because the cost of building and operating new plant has little to do with the cost of older plants on the Company's books. Options 3 and 4 make an attempt to correct this by depressing the demand cost of the first block so that a tail block could be set at marginal demand costs. No estimate of the marginal demand cost has been provided since this option is not recommended by Hydro at this time.

Another option would be to drop the energy rate below marginal costs and raise the demand charge with the difference. In order to judge whether this is a good idea or not, the rate designer has to make decisions about the relative importance of demand and energy. Full knowledge of the future expansion plans is an important component of that decision.

Both Options 3 and 4 would seem to offer the opportunity to have the best of both worlds. That is, a revenue requirement based on existing embedded cost, and a price signal for additional demand and energy set at marginal cost. Both come at a price, however. If NP keeps demands below the threshold demands (either the forecast NP demand or the somewhat arbitrary 800 MW of Option 4), the demand rate seen by NP will be lower than what it would have been in Option 2 and one would presume that even Option 2's demand rate is already below marginal cost.

This last presumption may be tested by looking at the demand charge for Option 2 and comparing it to an estimated marginal demand cost. The proposed demand charge of $4.58/kW-month will generate $54.96/kW-year for a twelve month ratcheted demand (12 x $4.58). At an assumed carrying charge of 10% for Hydro, a $1,000/kW combustion turbine would cost about $100/kW-year. Therefore, the presumption that the demand charge in Option 2 is below marginal cost appears to be correct.

There are many ways of estimating marginal cost. The one I have used here is a very common technique known as the peaker method and, of course, I am making very crude estimates of the cost of a peaker (combustion turbine). In the peaker method, marginal demand costs are estimated as the most inexpensive way of meeting short duration demand. This is a combustion turbine for most systems. The marginal energy costs in the peaker method are estimated as the cost of the most expensive unit on line with surplus capacity.

Final judgement on the actual avoided or marginal demand and energy costs of Hydro would require a more detailed marginal cost study and more disclosure of what the long term generation expansion plan would be.

For now, it appears that Option 2 is a good way to get a reasonable three-part rate for NP and gain experience with its use. I think the Board should approve the rate subject to review of the details on how it is working and without the twelve month ratchet for reasons which I will discuss later.

While it appears that the marginal cost calculation done by Hydro is based on a cost of oil of $18 rather than $14, in the interest of gradualism moving NP from an all-energy rate, this energy charge can be accepted. Gradualism is required because the proposed three-part rate changes NP's energy charge from 4.70¢/kWh (proposed May 1, 1992) to 3.40¢/kWh (proposed January 1, 1993).

Q. Why are you not in favour of the twelve month ratchet?

A. The twelve month ratchet has several harmful side effects that cause me to favour a non-ratcheted demand charge.

First, the existence of the demand ratchet causes a mismatch between the revenues NP receives from its demand metered customers who are not on ratchets and the revenues NP would have to forward to Hydro each month. There is a lot of volatility in monthly demands of NP, that in the long run, average out. Unfortunately, however, with a twelve month ratchet, an abnormally high demand in one month would obligate NP to pay significantly more to Hydro for the whole year. Revenues to NP from its customers would not be forthcoming in the other eleven months to offset this. From a risk and cash flow standpoint to NP, it would therefore be better for Hydro to have a non-ratcheted demand as well.

The twelve month ratchet can be perceived as promoting consumption, not conservation. That is because once a customer establishes a high level of demand, there is little incentive to stay under that level for the next eleven months.

The issue of demand ratchets was explored in NP's 1982 and 1987 hearings and the Board decided in those proceedings to support not having twelve month ratchets for NP's customers.

In moving away from the twelve month ratchet to monthly demands, I am also recommending removal of any floor on demand billing.

Q. What is your assessment of Hydro's proposal to have the Isolated Rural rate for the first 700 kWh automatically track NP's rates, but not the amounts over 700 kWh?

A. Because NP and the industrial customers are providing the rural subsidy, not only for the first 700 kWh (which are artificially low to track NP's rates) but also for any subsidies above 700 kWh and because the magnitude of the subsidies are large, I see no good reason to limit the tracking of NP increases to only the first 700 kWh. If there is a concern that this would create too much of an increase for these customers in a short period of time, perhaps a limit of no more than 10% per year should be established for the tracking increases.