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.