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BY EMAIL and RESS

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Ontario Energy Board
2300 Yonge Street
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Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2012-0340 – Ontario Power Generation – IRM Options

We are counsel for the School Energy Coalition. Pursuant to the Board's letter dated September 19, 2012, these are SEC's first round submissions on the issues.

General

Use of IRM

SEC starts with the observation that IRM as a rate-setting method has two fundamental components:

- A formula or other method for setting rates for multiple years, such that rates are predetermined for more than one future year. As the number of years into the future becomes longer, rates become increasingly decoupled from actual costs.

- A set of rules or principles for allocating the risk that costs or revenues will vary from those assumed for the purpose of setting rates. The default is that the utility's shareholder will bear those risks, but through Y factors, Z factors, and in some components X factors, some aspects of costs or revenues that affect rates are usually allowed to vary the rates during the IRM period. The more the rates are decoupled from actual costs (and assumed revenues), the more these other mechanisms are important.

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We generally assume that the rate-setting component will be some formula, based on some combination of forecast costs and expected escalation rates for those costs. Costs are forecast into the future either on an overall basis, or based on some components, and sometimes the risk of sales volume lies with the utility, and sometimes with the ratepayers.

For example, the price cap mechanism assumes that a formula can be developed which properly estimates future reasonable cost increases per unit sold based on past experience. The revenue cap mechanism assumes a similar formula, but measuring cost increases overall, rather than on a unit basis. Both cases typically start with a full cost of service review, or rebasing, so that a solid baseline is created on which to apply the formula.

Because most IRM models handle the rate-setting side of the process on a formula basis, with as little as possible input from cost changes after the first year, it is generally agreed that normal IRM structures only work when the future will be similar to the past. Formulae based on past data can only be valid in a future that is like that past data. That's why the data is predictive.

Clearly in the case of OPG the future of the prescribed facilities over the next decade will be very different from the last decade, and any formula based on past data would be either completely misleading, or predictive only if done at a very granular level. Below we give a number of examples showing why this is the case, but we expect that this is not in dispute.

It is important to note, however, that the use of a rate-setting formula is only part of the IRM concept. It is not an essential element. No matter how rates are initially set, the process of assigning risks and rewards based on future performance is at the essence of "incentive" rate mechanisms, as it focuses on what happens when there are variations from the baseline. As long as the baseline is known in advance, how it is set is largely irrelevant.

Our proposals below, therefore, start from the premise that expected cost changes have to be built into the base rates, and that the key aspect of IRM for OPG is in the assignment of risks and rewards relating to variations between forecast and actual.

Hydroelectric vs. Nuclear

In the analysis below, we identify specific reasons why rate-setting based on formulae are generally not appropriate for either the hydroelectric or nuclear prescribed facilities. Simply put, there is good reason to believe that the future in each case will not be similar to the past.

Thus, in both cases we propose that rate-setting should be done on a multi-year cost of service basis. The doesn't mean IRM is inapplicable. It just means that the focus is on the assignment of risks and rewards – the "incentive" side of the process.

For that reason, we have analysed the two parts of the regulated business separately. We believe that the issues to be addressed in the two cases are quite different, and, as a result, the incentive mechanisms used for hydroelectric and nuclear should be different as well.

Hydroelectric Prescribed Facilities

Initial Rate-Setting

The hydroelectric prescribed facilities are generally more than fifty years old. With the exception of the Niagara Tunnel, there is little prospect for expansion, and capital investments, while not trivial, will not average more than the level of depreciation in the foreseeable future.

There are three main components to the revenue requirement for hydroelectric:

1. ***Costs relating to rate base.*** This includes cost of debt and equity, PILs, and depreciation. In 2012 this is 52.4% of revenue requirement.

2. ***Operating Costs.*** These costs are largely stable, and are the main area in which short term productivity gains can be achieved. In 2012, OM&A is 17.8% of revenue requirement.

3. ***Gross Revenue Charge.*** This is a combination of property taxes and water rentals, and has recently been flat year over year. In 2012 it is 37.3% of revenue requirement.

With the exception of the Niagara Tunnel project, expected to come in-service in 2013, rate base is expected to be stable over the medium and perhaps even long term. Since capital additions after 2013 are not likely to exceed depreciation, rate base can be expected to go down. Thus, subject to changes in interest and tax rates, the total of all costs relating to rate base can be expected to go down year over year in absolute terms (since depreciation would be constant, and everything else would decline).

Operating costs can reasonably be expected to increase at an inflationary pace, subject to productivity and efficiency improvements. Reasonable productivity and efficiency are likely to be higher than some industry averages, given OPG's well-documented issues with compensation and staffing levels. While clearly less problematic in hydroelectric compared to nuclear, they still exist. On the other side, the stations are old, so there is a continuing need for strong maintenance and renewal programs. These factors suggest that operating costs will, with diligent management, remain relatively flat or increase at a low rate.

The GRC has remained flat, and there appears to be no evidence that it will increase in the near term. In any case, it would almost certainly have to be a Y factor, meaning that for initial rate-setting purposes it should be assumed to stay constant.

All of this suggests that, in setting base rates, using current rates or revenue requirement, plus an escalator, would be too high. In fact, from 2011 to 2012 both rates and revenue requirement went down, and in general static or declining costs can be anticipated in the future.

Into this mix will be thrown the Niagara Tunnel, which will increase rate base by about 40% but may not increase production by a similar amount. There is no reasonable way to build the impact of this major change into rates for future years without doing a multi-year forecast of the individual cost and revenue categories that will be impacted.

SEC concludes from this that, after 2014, the cost structure of the hydroelectric prescribed facilities will be at an apex. Subject to certain predictable elements (interest and tax rates, GRC, etc.), the unit cost and revenue requirement for these facilities will thereafter likely decline, at least relative to inflation, and more likely in absolute terms.

In these circumstances, it is submitted that establishing a formula on which to set rates is premature. The costs for the period 2014 through 2018 are not smooth, but they are predictable. Once those costs have been established and monitored, it will be possible for the Board to determine an appropriate formula to capture the appropriate rate pattern going forward.

SEC therefore proposes that initial rates be set for the period 2014 through 2018 based on a multi-year cost of service application to be filed in 2013. The Applicant can propose methods of forecasting cost pressures for individual areas of costs, and the Board can assess in each case what is reasonable in the circumstances. This will facilitate, for example, a careful review of compensation cost control targets going forward, and other areas of productivity and efficiency improvements.

As with any multi-year cost of service application, in our submission the application for five years of rates should be supported by a ten year outlook (which we know OPG prepares internally in any case), so that the Board can see the context within which the first five years of base rates are being established.

Assignment of Risks and Rewards

SEC believes that in general the hydroelectric prescribed facilities are a mature business in which operations are both predictable and within the core competency of OPG management. While there are a number of exogenous factors impacting the business, those factors, while volatile in any given year, are still fairly predictable over longer periods. Therefore, on balance SEC believes that protections for either the shareholder or the ratepayers should be limited.

The following are potential areas for the assignment of risks and rewards during the initial period of multi-year cost of service:

1. ***GRC.*** In our submission the GRC rate, but not amount, should be a Y factor throughout the period of multi-year cost of service. Rates should be set initially using the current level of GRC and production forecast. If production varies, the GRC is self-adjusting. If, however, the rate at which the GRC is charged changes, in our view this should be a pass-through.

2. ***Surplus Baseload Generation.*** OPG is currently protected from the impact of SBG, and the need to spill water to compensate. While it is in part an exogenous factor, OPG should also be managing – as any private sector company does – to respond to its market in the most efficient manner. Therefore, SEC believes that the SBG protection

should be removed. A basic assumption as to SBG should be built into revenue requirement for each year, and variations should be for account of the shareholder.

3. ***Hydroelectric Incentive Mechanism.*** For the same reasons, SEC believes that HIM should be removed. A forecast of pumped storage premium for an average year should be used in setting rates, and if OPG can operate its peaking capacity more efficiently, it should keep the incremental profits. Of course, when it comes time to rebase, for example for a price cap or revenue cap system starting in 2019, the experience of the initial period will inform the Board on the baseline to set for the subsequent period.

4. ***Hydroelectric Water Conditions Variance Account.*** OPG and the ratepayers are currently protected if water conditions are more or less favourable compared to those assumed in setting initial rates. This makes sense in a one or two year cost of service. In a five year period, it is less necessary. In our submission, this protection can be removed, and water conditions (which are in essence a type of weather risk) can be assigned to OPG the same way that weather risk is assigned to wires companies.

5. ***Earnings Sharing Mechanism.*** SEC has consistently opposed ESMs, saying that it is better to give utilities

    a. the full incentive to perform well, rather than to remove some of the incentive and give it to the ratepayers when utilities do perform better than expected, and

    b. the full risk of performing poorly, rather than providing a partial safety net in the form of ratepayer sharing of that risk.

    OPG is a case in point. Reasonable productivity and efficiency gains can be built into the multi-year cost of service rates. Beyond that, performance that is better or worse than the reasonable level should be for account of the utility and its shareholder.

6. ***Pension/OPEBs.*** An area of increasing concern is the variability of pension and OPEBs costs. SEC believes that, while this cost category is in its current very volatile period, it is appropriate that a variance account be established and maintained to capture the annual changes in these costs. After the initial period to 2018, it may be possible for the Board to change this, if this cost area has by that time become less volatile.

7. ***Z Factors.*** Because the base rates for the five year period would be set based on a cost of service forecast, the use of Z factors should be much more limited than is normally the case with a formula-based IRM. Similarly, it is not necessary to have an ICM or other specific capital component, because capital spending will be part of the cost of service forecast.

Conclusion – Hydroelectric

Based on the foregoing, SEC proposes that the basic hydroelectric payment amounts be set for the five years 2014 through 2018 based on a multi-year cost of service filed and decided in 2013. Except for the GRC and Pension/OPEBs, the rates should be considered fixed and should generally not be subject to future adjustment during that five-year period. Some existing variance accounts would be removed.

Nuclear Prescribed Facilities

Initial Rate-Setting

If anything, the cost structure of the nuclear prescribed facilities will have more changes in the next several years than hydroelectric.

The most obvious changes are in capital. The Darlington Refurbishment Project will add significant rate base in 2018 and beyond, but prior to that time the lost production from units taken out of service will have major impacts on cost per unit of production. In conjunction with the Darlington effects, the Pickering units will be relied on at increasing levels, and then taken out of service. This will have effects on rate base, decommissioning costs, and nuclear fuel disposal costs.

Capital costs are, in the case of nuclear, only 20.2% of revenue requirement in 2012, but they will be volatile for at least the next eight to ten years, eventually becoming a much higher percentage of revenue requirement. Underlying that, though, nuclear capital costs should, like hydroelectric, decline over time due to depreciation exceeding capital additions. The major changes go against that trend, but they can and should be forecast, as can the underlying trend downwards.

OM&A is the biggest component of nuclear costs, at 68.9% in 2012, but it will decline in the next decade, for three reasons. First, OPG, with the encouragement of the Board, has embarked on a major productivity and efficiency push in the area of nuclear OM&A. It is reasonable to expect that as that initiative gains traction OM&A costs will go down. Second, the refurbishment of Darlington should result in lower annual operating costs, at the very least on a units of production basis, due to the renewal of the assets. Third, as the Pickering units are taken out of service, fewer personnel will be needed for those OM&A-intensive facilities. Some of those staff will retire, some will move to decommissioning and fuel disposal activities, and some will be surplus.

The main area of growth in nuclear costs, aside from the refurbishment, will be in decommissioning and fuel disposal. However, those cost categories are highly predictable. In any case, OPG is not expected to take the risk of increasing costs in those areas. They are either funded, or a pass-through.

There appears to be a consensus amongst all stakeholders that, given the above realities, and others described in the Power Advisory and LEI materials, it is not realistic to set rates for OPG in the next several years based on a formula.

SEC therefore proposes that base rates be set, as with hydroelectric, based on multi-year cost of service, likely starting with the same five year period of 2014 to 2018, and with a ten year outlook as context. Unlike hydroelectric, however, we believe that the following five year period may also have to be on multi-year cost of service, for the same reasons.

Assignment of Risks and Rewards

With rates set based on multi-year cost of service, nuclear too would have less need for protections based on actual costs. There are some protections that are statutory, of course, and others that are special requirements due to the nuclear business, and we will not comment on those.

However, there are two variables that we believe should be discussed with particular emphasis on nuclear: ESM and benchmarking.

Benchmarking. The Board has encouraged OPG to use benchmarking to improve its performance, particularly in its nuclear operations. OPG has taken solid steps in that direction, and in our view the Board should continue to promote this approach.

In this respect, SEC was surprised to hear London Economics say, during the stakeholder conference, that “nuclear executives won’t work if they have to meet external standards”. We doubt this is true of OPG executives, and if it were, it would appear to us that the answer is to get executives who will meet those standards. The job of executive management in any major organization is to manage to an external reality: market changes, competition, resource availability, etc. Success is measured by one’s ability to perform as well as, or better than, your peers given those realities.

Therefore, SEC believes that the Board should continue to require benchmarking by OPG of major components of its nuclear operations.

Benchmarking, though, is implemented by the regulator differently in IRM-type systems than in conventional cost of service. The key difference is that some aspects of performance that might otherwise be benchmarked after the fact are inherent in the rate-setting and IRM structure. For example, cost control can be built into the multi-year revenue requirement forecast, with variations up or down automatically incented (positively or negatively) through the resulting bottom line each year.

In our submission, there are two key elements that need to be considered separately: availability and safety. Availability is a key aspect of overall production levels, but those levels are also heavily influenced by market demand. Safety also has impacts on the income statement, but those impacts are limited, and safety is a non-financial goal in and of itself.

OPG has proposed a scorecard approach. We agree, and we propose that the Board develop a scorecard based on availability and safety metrics for the nuclear prescribed facilities. The metrics would be compared to external benchmarks based on comparator groups: either other CANDU stations, or all North American nuclear stations.

SEC also proposes a unique approach to incenting scorecard performance. The initial scorecard should be established based on benchmarking of existing and target performance to comparator groups. For example, Darlington availability might be compared to all North American nuclear stations, with the target being the 50th percentile. Pickering safety, on the other hand, might be compared to CANDU stations, with the target being the 80^{th} percentile. The overall scorecard would be a composite of all of these comparisons.

SEC proposes that OPG should have the Board's formula ROE built into its revenue requirement. Initial rates should be set on this basis. This assumes the target level of composite performance.

Then, each year when rates are reset, actual performance for the immediately preceding year relative to the comparator groups should be determined. To the extent that the actual performance is better or worse than the target level relative to the comparator groups, the ROE rate for the upcoming year would be adjusted upward or downward. In effect, a better-performing company earns more money, and vice versa.

By way of example, assume a simple case of all metrics being set at the 50^{th} percentile (not likely, but chosen to illustrate the mechanism). Rates for year 3 of the multi-year cost of service are set assuming ROE of 9.00% on a $2.0 billion equity component of nuclear rate base. Thus, revenue requirement for that year includes $180 million for ROE and about $50 million for PILs on that ROE.

Assume further that performance is at the 55^{th} percentile in year 1. In the Application to set adjusted rates for year 3, OPG would include an adjustment to ROE up to 9.50% (10 basis points per percentile of improvement, in this example). Only the rate would change. Rate base would remain at the built-in amount, as would the tax rate. As a result, the performance improvement would increase OPG's ROE for year 3 built into ratesto $190 million, and PILs to $52.8 million. For that additional $12.8 million, ratepayers would have received an improvement in availability and safety performance. In the long-term, ratepayers will receive significantly more benefit from these operational improvements than the incentive paid.

The same would hold true if performance were 45% rather than 55%, but the new ROE would be below the built-in rate, not above.

Of course, the actual scorecard and adjustment metrics would have to be worked out in detail, and the example is a very simplified version that would not play out in practice. The point is that OPG's profitability would be directly tied, not just to its cost-cutting efforts, and to the market for its product, but also to its ability to improve availability and safety over time.

ESM. As with hydroelectric, and for the same reasons, SEC believes that ESM is not appropriate for the nuclear prescribed facilities. What is more appropriate is that strong productivity and efficiency targets should be built into approved rates, and management of OPG should be charged with the responsibility of meeting those targets. To the extent that they perform beyond those levels, ratepayers will get the benefit in the next rate-setting period. To the extent that management do not meet the targets, the return to the shareholder will be eroded.

In this regard, we note in particular the suggestion by some participants in this discussion that the targets in the OPG Business Plan should be sufficient. In SEC's view, that may or may not be the case. With respect to any given target, the Board should hear evidence in the multi-year rate-setting proceeding as to the productivity and efficiency improvements being planned. The Board can then make a determination as to whether those improvements are sufficient. We saw in EB-2010-0008 that, even where OPG establishes such goals, they may not be enough. It is certainly inappropriate for the Board to simply delegate the assessment of these targets to the utility, as some would propose.

Conclusion

Our conclusion, therefore, is that as with hydroelectric the rates for the nuclear prescribed facilities should be established based on a five year cost of service proposal. Unlike hydroelectric, nuclear would likely then have to be set for the next five years also on cost of service. By using multi-year cost of service, forecast costs and cost improvements still form the basis of rates, but actual costs are increasingly decoupled from rates. Thus, this operates like a modified form of IRM.

SEC proposes that nuclear, like hydroelectric, operate without an ESM, but we have suggested a benchmarking approach that would tie ROE each year to performance on scorecard metrics that are not otherwise captured in the IRM model: availability and safety.

SEC appreciates the opportunity to provide input on these important issues, and plans to respond to the submissions of others in the second round of submissions.

All of which is respectfully submitted.

Yours very truly,
JAY SHEPHERD P. C.

Jay Shepherd

cc: Wayne McNally, SEC (email)
Interested Parties