Board of Commissioners of Public Utilities Discussion Paper on the Rate Stabilization Plan for Newfoundland and Labrador Hydro

Grant Thornton

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Introduction

Newfoundland and Labrador Hydro's ("Hydro", "the Company") Rate Stabilization Plan ("RSP") was established effective January 1, 1986 with the objective of providing rate stability to customers and providing a mechanism to eliminate volatility in Hydro's revenue requirement due to events beyond their control. As established, the RSP provided for adjustments to recover differences between the forecast test year costs used to set rates and the actual costs attributable to:

- differences in the price of No.6 Fuel;
- variations in hydraulic production; and
- variations in load.

The plan was later modified in 1993 to include an adjustment to account for any variation in Hydro's rural revenues which may arise as Hydro's rural rates are changed, in accordance with Government policy, to reflect Newfoundland Power's rates. This provision was incorporated into the RSP as part of the 1993 generic cost of service hearing. Further changes were made in 2002 flowing from Hydro's 2001 General Rate Hearing. These changes are summarized in a later section of this paper.

During 2001, the balance in Hydro's RSP increased to approximately $85 million as compared to $34.7 million in 2000. This dramatic increase in the RSP balance, together with the forecast cost of No. 6 fuel, generated significant concern and discussion with respect to the RSP during Hydro's 2001 General Rate Hearing. In its decision on the 2001 Hearing, the Board stated that it was "convinced, based on the evidence and issues raised during the year, that the design and elements of the existing plan should be reviewed." (P.U. 7 (2002-2003) pg.84).

This Order included a requirement for the completion of a study relating to the RSP. Flowing from this requirement the Board requested Grant Thornton LLP to undertake a review of the RSP.

The scope of our engagement with respect to this review is to provide a report that will serve as a discussion paper on the RSP which will address the following:

- Brief description of the history of the current RSP.
- Discussion of issues that were highlighted by various intervenors during the 2001 General Rate Hearing of Hydro.
- Discussion of possible modifications to the current RSP.
- Examples of how other regulated utilities account for fuel costs in other jurisdictions.

This discussion paper will hopefully provide some focus to the issues which the Board and other stakeholders may wish to consider in assessing whether further changes to Hydro's RSP are appropriate.

Background Information on the RSP

Prior to the establishment of the RSP in 1986, Hydro used two separate accounts, a water equalization provision and a fuel adjustment charge, to adjust for variations in hydraulic and thermal production costs as compared to the test year forecasts that were used in the calculation of the rates Hydro charged its customers.

The water equalization provision was used to adjust costs of production due to variations in hydraulic generation which were caused by fluctuations in water availability. The fuel adjustment charge was a mechanism designed to pass on actual fuel costs to customers one month after they were incurred. This method of recovery resulted in significant volatility in electricity costs to customers, particularly in the winter months when consumption would be at its highest. During the early eighties fuel prices experienced substantial increases. This resulted in the public expressing discontentment due to significant increases in their monthly electricity bills as a result of the operation of the fuel adjustment charge.

In 1985, as a means to address consumer concerns and reduce volatility in its revenue requirement, Hydro proposed implementation of a Rate Stabilization Plan. The RSP would reduce volatility and improve stability of rates but ultimately all variations in costs would be borne by consumers. The RSP consolidated both the hydraulic and fuel adjustment charge accounts into a single plan. As previously noted, the proposed RSP was accepted by the Board effective January 1, 1986 and was subsequently modified in 1993 and most recently in 2002.

The 2002 changes flowed from the Board's Decision on Hydro's 2001 Rate Hearing. In that Decision the Board considered the concerns and recommendations of the various parties and ordered certain changes to the operation of the RSP as follows:

- The balance in the plan as of August 31, 2002 would be fixed and recovered over five years, commencing in 2003, using the straight line recovery method.
- The cost of service price per barrel of No.6 Fuel was increased to an average of $25.91 per barrel in comparison to $12.50.
- The Hydraulic forecast was increased from 4,205.32 GWh to 4,425.00 GWh
- The Holyrood average annual operating efficiency rate was increased from 605 kWh to 615 kWh per barrel.
- The “new” RSP balance that started as of September 1, 2002 would be recovered over two years, commencing in 2004, using the straight line method.

Several other changes proposed by Hydro that were accepted by the Board are as follows:

- addition of mini-hydro plants to the calculation of the hydraulic production variation;
- exclusion of interruptible energy from the plan;
- use of 12 month-to-date invoiced/bulked transmission energy, as well as Rural deficit allocation, to determine RSP split instead of using test year Cost of Service study;
- establish energy rates on the same basis as the split; and,
- change the finance charge from Hydro’s embedded cost of debt to Hydro’s weighted average cost of capital.

In order to facilitate this review of the RSP we have prepared the following summary description of the plan components and its general workings as it exists today, incorporating the 2002 changes.

The main components of the RSP are:

- fuel cost variation
- hydraulic production variation
- load variation
- recovery
- interest charges

Fuel cost variation - On a monthly basis the difference between the actual cost of No. 6 fuel consumed and the test year forecast cost is calculated and the plan is either charged or credited accordingly. The adjustment amount is determined by multiplying the difference in fuel cost/barrel by the actual number of barrels consumed in the month. For example in December 2002 the actual average cost of fuel was $35.98/barrel, the cost of service price was $26.80/barrel and the number of barrels consumed was 439,726. The December 2002 fuel cost adjustment was $4,037,000 (($35.98 - $26.80) x 439,726). This amount was charged to the plan to be recovered from consumers in the future.

Hydraulic production variation - Hydro's rates are set based on a test year forecast of generation mix (hydraulic versus thermal). The hydraulic generation forecast is based on average water availability and therefore actual hydraulic generation will vary from the forecast depending on rainfall, water inflows, etc. A variation in the generation mix impacts Hydro's cost as a change in thermal generation impacts the amount of fuel consumed. The hydraulic production variation adjusts, on a monthly basis, for the difference in fuel costs associated with a variation in generation mix. If hydraulic production exceeds cost of service levels, it results in a credit to the plan (a saving in fuel costs), whereas, if hydraulic production is less than cost of service levels there is a charge to the plan for the additional fuel cost. The adjustment amount is determined by dividing the difference in actual versus test year hydraulic production by the fuel conversion factor and then multiplying by the test year cost per barrel of fuel. For example, in December 2002 the actual hydraulic production was less than the cost of service level by 57.19 GWh, the fuel conversion factor was 615 kWh/barrel and the test year cost of fuel was $26.80/barrel. The December 2002 hydraulic adjustment was $2,492,000 (57.19 GWh/615 kWh x $26.80). This amount was charged to the plan to be recovered from consumers in the future.

Load variation - The load variation included in the RSP includes two components; a revenue component and a fuel component. These two components together adjust for the net contribution attributable to a variation in energy sales. With respect to the revenue component, if the actual energy sales are less than the cost of service sales the difference flows through the plan as a charge to the particular customer group (i.e. retail verses industrial), and vice versa, if the sales are greater than the cost of service sales, the difference is a credit for the particular customer group in the plan. The adjustment amount is determined by multiplying the difference in actual versus cost of service energy sales for each customer group by their respective energy rate. The fuel component of the load variation is calculated by taking the total sales in kWh's from both customer groups, comparing it to the total cost of service kWh sales and multiplying the difference by the thermal generation energy rate. If the actual sales are less than the cost of service, the fuel component is a credit to the plan and if the actual sales are greater this component would result in a charge to the plan. For example, in December 2002 the actual energy sales were less than cost of service sales for both the utility and industrial groups by 26.79 GWh and 5.96 GWh respectively. The revenue component adjustment was $1,283,000 (26.79 GWh x 4.789¢/kWh) for Newfoundland Power and $142,000 (5.96 GWh x 2.388¢/kWh) for industrials. The fuel component adjustment was $1,427,000 ((26.79 + 5.96 GWh) x 4.358¢/kWh). The revenue component adjustments were charged to the plan while the fuel component adjustment was credited to the plan.

Recovery - The adjustments charged or credited to the RSP are allocated pro-rata to the retail and industrial customer groups on the basis of actual energy sales for these two groups over the last twelve months. The exception to this is the revenue component of the load variation which is allocated as described above. The resulting balances in the plan are to be recovered from customers over a two year period on a straight line basis.

The recovery is achieved by adjusting energy rates effective January 1 for industrials and July 1 for the utility customer. The amounts recovered are applied against the outstanding balances on a monthly basis.

Interest - The cost of financing the balance in the RSP is calculated using Hydro's weighted average cost of capital and added to the balance on a monthly basis.

In addition to the main components described above, Hydro's RSP includes two other adjustments: the rural rate alteration; and a reallocation of the rural share between the utility customer and Labrador Interconnected.

Rates charged to Hydro's rural customers are based on Newfoundland Power's rates. When these rates are adjusted in between Hydro hearings, the difference in revenue generated by Hydro's cost of service rates versus the Newfoundland Power rates is flowed through the RSP (the rural rate alteration) with a corresponding adjustment to Hydro's revenue.

The rural portion of the net activity flowing through the RSP gets reallocated between the utility and Labrador Interconnected customers based on the deficit allocation ratio established for the 2002 test year.

Discussion of Issues Arising From 2001 General Rate Hearing

During the proceedings of the 2001 Hydro General Rate Hearing, several of the intervenors, most notably the expert witnesses of the Consumer Advocate and the Industrial Customers, expressed concerns relating to the operation of the RSP.

The issues raised during the Hearing were primarily related to the following:

- the inclusion of the “load variation” as a component in the plan;
- the recovery period of the plan and the fact that it uses multi-year balancing accounts;
- the amount of the outstanding balance in the plan; and
- the complexity of the components included in the plan.

It was noted in the 2001 Hearing that based on a survey conducted of Canadian utilities by Hydro, no other Canadian utility uses an RSP account and, according to NRRI, no US utility uses an RSP account. However in 1991, the NRRI conducted a comprehensive survey of fuel adjustment cost practices in the United States. Dr. John W. Wilson of J.W. Wilson and Associates, Inc. noted that, in general, the information in this survey indicates that most States have fuel adjustment cost mechanisms and States with substantial hydroelectric production usually include hydroelectric availability in some manner. However, there do not appear to be any States that include the cost impacts of demand or sales variation (i.e. load variation) in the fuel cost adjustment methodology.

The load variation component of the RSP is an adjustment based on actual energy sold compared to forecast energy sales included in the cost of service. Higher actual sales would result in a savings to the plan and lower sales would result in a cost to the plan. It was suggested during the 2001 Hearing that the load variation component serves to protect Hydro from (and transfers to customers) all risks to load variation and errors in Hydro’s forecasts, regardless of the source of the variations, which is a risk that is normally borne by the utility.

It has been suggested that utilities should not use multi-year balancing accounts in the operation of their fuel adjustment clauses, in particular, because they can distort price signals, cause cross subsidization among past, current and future customers, and provide minimum incentive for a utility to better manage its fuel costs.

It was also argued that the RSP violates the generally accepted utility practice of matching rates to costs in the period in which they occur. Reference was made to the Board's 1992 Report on Proposed Rates to be Charged to Newfoundland Light and Power Company; in this report it was noted that Newfoundland Power "submitted that cost deferrals are against generally accepted utility practice of matching rates to costs in the period in which they occur and that cost deferrals should not be made especially when they can be reasonably avoided." Others argued that the RSP did promote rate stability and predictability for customers and that the recovery period (three year, declining balance) was within a reasonable time frame as not to hinder intergenerational equity.

In general, the discussions at the Hearing also questioned whether the protection that Hydro was receiving as a result of variations in fuel prices, generation mix and forecast load being passed through the Plan would undermine possible efficiencies in the production of energy.

Possible Modifications to the Current RSP

In this section of our report we have outlined for further consideration potential options with respect to modifying the current RSP to address some of the specific concerns and issues noted previously. The modifications presented may represent complete alternatives to the existing Plan or may be incorporated individually or in a combination into the current RSP. As part of the discussion both the benefits and the shortfalls of the potential modifications are noted where appropriate. The potential modifications discussed are as follows:

- Load variation component
- Recovery period of the RSP Balance
- Recovery period of Hydraulic versus Fuel Cost Variance
- Hedging Programs
- Fuel Price Risk Management
- Partial Pass-Through Mechanisms

The options presented above and described in more detail below are the result of research conducted on the topic in North America. This research included a thorough review of the evidence presented at the 2001 General Rate Hearing, a review of various articles and reports on the subject of fuel adjustment clauses as well as reviewing decisions issued by regulatory bodies in various jurisdictions in North America. In conducting this research we were assisted by Dr. John W. Wilson of J.W. Wilson Associates, Inc.

Load variation component

As previously noted, the load variation included in the RSP includes two components; the revenue component and the fuel component. These two components together adjust for the net contribution attributable to a variation in energy sales in any given year in comparison to test year energy sales forecast. In effect, if actual energy sales in a year are lower than the test year sales, then the shortfall (less the related fuel savings) is recovered from consumers through the RSP. Conversely, if actual energy sales are greater than the test year sales, then the extra revenue (less related fuel costs) is returned to consumers through the RSP. Essentially, Hydro does not bear any risk, nor does it benefit, from variations in energy sales relative to the test year forecast. This risk/benefit is borne 100% by consumers.

As previously noted, during the 2001 General Rate Hearing there was opposition expressed by the Consumer Advocate and Industrial Customers expert witnesses regarding the inclusion of the load variation component in the RSP. The main issue raised with respect to the inclusion of the load variation component in the RSP is that Hydro is currently protected from variations in its forecasting of sales to its customers. The arguments presented noted that the risk of Hydro overstating its forecast sales is passed on to customers, and it is not appropriate to penalize the ratepayers for this additional cost. Of course, where forecast sales are understated the benefit is passed on to ratepayers.

The elimination of the load variation component is an option the Board may wish to consider with regards to the operation of the RSP. The elimination of this component would basically transfer all risk associated with the forecast of load requirements from customers to the Company. In considering this modification the Board should address such issues as:

- the risk of significant variations or volatility in load in future years;
- how significant would the load variations have to be to have an impact on Hydro’s financial stability;
- should consumers bear the risk or receive all the benefit of variations in load forecasting.

Recovery Period of the RSP Balance

The current mechanism for recovery of balances in the RSP requires that the balance be recovered over a two year period on a straight line basis. This is one of the changes ordered by the Board in P.U. 7 (2002-2003). Prior to the 2001 Hearing and the recent change, the period to recover the balance in the RSP was three years using the declining balance method. This change for 2002 represents a significant improvement in the recovery mechanism.

As noted previously, during the 2001 Hearing there was considerable discussion regarding the length of the recovery period for RSP balances. The issue with respect to the recovery period is primarily related to the distortion of price signals for ratepayers. It was noted during the Hearing that, according to the NRRI, no U.S. state utilizes a fuel adjustment clause that balances (extends recovery) over a period greater than one year. The distortion of price signals could result in ratepayers increasing their consumption when fuel prices are high and conserving energy when prices are lower. Currently, in the RSP, when fuel costs are increasing, the consumers are not seeing it in their electricity bills; instead it will become a part of rates in future years when fuel prices could actually be experiencing a decline.

Experience over the past six months would appear to support this premise of distortion in price signals. During this time period, as a result of world issues, the price of oil exceeded the forecast costs that were presented at the 2001 Hearing by upwards of approximately $10 per barrel. Consumers that use oil heat rather than electricity would normally receive the price signal relating to the increasing cost of fuel in their monthly oil bills or annually if the customer participates in an equal payment plan. However consumers that use electric heat did not see any resulting changes in their electricity bills during this time period, and therefore conservation may not have been an issue for these consumers. The change for these consumers is spread over the following two years as the balance in the RSP is recovered.

The arguments against a shorter recovery period have made reference to the principle of rate stability. Ratepayers would prefer stability in their electricity rates as opposed to being subject to rate volatility. Also, with such significant balances accumulating in years when hydrology is low and fuel costs are significantly high, rate shock could also be an issue if there is a reduction in the time period to recover the additional costs.

However, consumers using oil heat have to respond to increasing prices at least annually, so others may argue why electricity consumers should be treated any differently.

A reduction in the recovery period of the balance accumulating in the RSP is an option the Board may wish to consider with regards to the operation of the Plan. In assessing this modification the Board should give consideration to the following issues:

- the impact that cost deferrals have on distortion of price signals;
- the impact that distortion of price signals has on system requirements;
- the benefits and relative importance of price stability for consumers;
- the potential for rate shock with a shorter recovery period.

Recovery Period of Hydraulic versus Fuel Cost Variances

Currently, the RSP recovers all variation components over the same time frame (two years, straight line). While individual components of the Plan are tracked and calculated independently, they are all aggregated into one balance to which the current recovery mechanism is applied. An alternative that could be considered is the use of different recovery periods for the different components, particularly the hydraulic production and fuel cost variations. As indicated by Mr. Osler, the expert witness for the Industrial Customers, "the water inflow provision is more suited to a longer term adjustment since forecasts are based on long term averages. In the absence of evidence of long term climate change that is impacting or predicted to impact inflows, over the long term the forecast of inflows should be correct." (Industrial Customers-Final Argument, Pg. 62). Fuel costs, on the other hand, can be very volatile over short time frames and can be driven by economic factors, political factors, world issues and supply and demand.

There is validity in examining whether the hydraulic production variation should be deferred over an extended period of time before recovery is warranted. In theory, hydrology is cyclical and it can be argued that over a period of years, the hydraulic variation component would be expected to balance itself. Consideration could be given to setting a cap for the maximum amount of "credits" or "charges" to the account before recovery is mandatory. The Board could then approve a surcharge or a rate reduction for a period sufficient to return the balance in the hydraulic variation component of the plan to an acceptable level.

The use of different recovery periods for the hydraulic production and fuel cost variations is an option the Board may wish to consider. A disadvantage of accepting the methodology of deferring the recovery of the hydraulic production variation component over an extended period of time would arise primarily in the "good water" years, when the hydraulic production would most likely exceed the cost of service production and result in credits to the RSP. Under the current plan, the credits that would result from "good water" years would be used to offset any charges in the plan balance. If different recovery periods were used, the offsetting of credits and charges for the various plan components would not occur. However, the opposite effect is also true, and that during "bad water" years, the additional charges relating to the hydraulic production variance would not be in addition to the fuel cost variation component of the plan.

Based on the activity for the first four months of the "new" RSP plan, the hydraulic production variance component comprises approximately $7 million of the $20.5 million overall plan balance. As indicated by Hydro in its Quarterly Report for the year ended December 31, 2002, the hydraulic production in 2002 was the second lowest in the past twelve years. The total annual inflows for 2002 were below normal and during the last quarter of 2002 the storage levels were below the year end minimum energy storage targets.

In considering modifying the recovery periods/mechanisms for different plan components the Board would need to address such issues as:

- whether using several recovery mechanisms will add to the complexity of the RSP;
- whether recovery mechanisms should be set based on the factors which drive the variations (e.g. hydrological cycle); and

- the current flexibility inherent in being able to offset credits in certain Plan components against charges arising from others.

Hedging Programs

During the 2001 Hearing, there was discussion of the purchase, storage and pricing mechanism for oil at the Holyrood Generating Station. The Board directed Hydro to file a statement of policies and procedures of its fuel oil practices and also requested consideration of an oil hedging program. Hydro filed a report on December 10, 2002 entitled “Fuel Oil Practices Review and Policy”, which includes a review of the possibility of implementing an oil hedging program.

Hydro retained the services of Risk Advisory, an independent risk management group, to review the fuel oil hedging. Risk Advisory recommended that prior to implementing an oil hedge program, Hydro undertake a review of the added stability such a program would have in addition to the RSP. This review was conducted by Hydro’s Oil Hedge Committee and consultation with Risk Advisory.

Hydro reported that based on their analysis of various scenarios there is an approximate 50% reduction in the variability of the rate impact, year over year by having the RSP alone. If there were a hedge program and no RSP, there would be an approximate 25% reduction in the variability of rate impact. However, it was noted that these two impacts are not cumulative and the impact of having both an RSP and a hedge program is approximately 60%. The report indicated that there would be an approximate $10 to $15 reduction in variability per ratepayer annually if there is an oil hedging program implemented in addition to the RSP. In the conclusion of the report prepared by the Oil Hedging Committee, they estimated that the transaction and administrative costs associated with the various hedge positions would be estimated at $480,000 Cdn.
This estimate does not include the added internal administrative costs. In its report to the Board, Hydro stated that the additional 10% stability is not considered substantial enough

to incur the additional administrative and regulatory costs that would be associated with implementing an oil hedging program, and recommended that Hydro not implement such a program.

An oil hedge program would not necessarily require a modification to the RSP itself, however it may be used in conjunction with the Plan to improve rate stability. In assessing the appropriateness of the hedge program, the Board should consider the report and recommendation presented by Hydro, and in particular the comparison of the incremental cost with the possible incremental stability provided by using both.

Fuel Price Risk Management

During the 2001 Hearing, the expert witness for the Consumer Advocate, Mr. Bowman, recommended that the RSP be eliminated, however he did indicate that a replacement mechanism would be required. Mr. Bowman indicated that he would like to see the RSP replaced by a mechanism that transfers a portion of the risk associated with fuel costs to Hydro. It was suggested that although Hydro is unable to control the amount of precipitation in a given year or the price of oil, there were some things that the Company could do to manage the risk to some extent. Currently, Hydro recovers all of its fuel costs from customers, either through rates (fuel base price) or through the eventual collection of balances in the RSP account. The 100% pass through of fuel expenses substantially transfers all of the risk of volatile fuel prices from Hydro to ratepayers.

There have also been concerns expressed that the automatic pass through of fuel related costs reduces the incentive for management to lower fuel costs. The automatic pass through also provides minimal incentive to improve fuel efficiency and can impact management's decisions on generation mix and maintenance schedules. Under the current Plan, Hydro does not benefit from any savings in fuel costs achieved through better management. Based on these arguments, it was suggested that it may be appropriate to share the risk between the shareholders and the ratepayers in some manner. The balancing of risks between shareholders and ratepayers may be accomplished through the partial recovery of fuel expenses in a fuel adjustment mechanism.

During the Hearing reference was made to a fuel price mechanism commonly used in Power Purchase Agreements. The energy component of a power purchase tariff often includes two features: the first relating to the conversion efficiency of the generator and the second relating to the price of fuel.

The conversion efficiency is essentially the same as Hydro's Holyrood efficiency factor. During Hydro's last hearing the efficiency factor for the Holyrood plant was set at 615 kWh per barrel. Setting the efficiency factor for the test year in this manner works as an incentive mechanism for Hydro. In the years between hearings Hydro would retain any savings that can be gained by improving efficiency at Holyrood. Of course, the Company would have to absorb any additional costs if the plant falls below the test year efficiency.

The second feature of the power purchase tariff is the fuel price component. It was suggested that fuel prices should be allowed to increase or decrease according to a published fuel price index. Using this methodology, if Hydro is able to manage its fuel contracts/purchases such that the cost of the fuel is less than the increase in the index, then Hydro would be entitled to retain the savings, however, if the Company does not do a good job of managing the fuel purchases, it will have to absorb the additional costs.

Both of the features, conversion efficiency and the fuel price component, can be considered to be incentives to Hydro to adequately maintain the units at Holyrood and to do its best in managing its fuel purchases, while taking into account that the Company has no control over the world oil prices. This methodology would also allocate some of the risk from consumers back to Hydro.

The type of modification described above would essentially be a replacement for the fuel variation component of the current RSP. If the Board wished to give further consideration to this modification then the issues to be addressed would include:

- approach and methodology for setting efficiency targets or selecting an appropriate fuel price index;
- approach to adjusting rates based on changes in fuel price index;

- impact of possible changes on rate stability for consumers;
- impact on Hydro's financial stability of sharing the risk of changes in fuel costs.

Partial Pass-Through Mechanisms

The objective of a partial pass-through mechanisms is also to transfer risk from the ratepayer to the shareholder and to provide the Company with incentives based on performance. In the context of Hydro's RSP, a partial pass through mechanism could be used with respect to fuel costs. Under such a mechanism, targets are set for fuel purchases, and, if the utility exceeds the target, then shareholders absorb the additional costs. However, if the utility's purchases are less than the target, they are permitted to keep a portion of the avoided costs. Some mechanisms are set up with a "band" in place. For example, the first $5 million in additional costs or savings would be either absorbed or retained by the utility, and the next $5 million would be shared by the utility and ratepayer by an agreed percentage, and then anything greater than that amount would be shared by another agreed percentage.

The concept of a partial pass-through of fuel costs can be considered controversial. Utilities may be able to provide a reasonable argument that they are being denied the recovery of prudent incurred costs. In fact, all fuel costs may be reasonable, meaning that the partial pass-through has denied the utility from recovering reasonable expenses and earning a reasonable return.

Another argument against the concept of partial pass through is the issue of the arbitrariness of the targets and/or percentages that would be required to be set by the Board. It may be difficult to determine on a factual basis what the appropriate targets and/or percentages would be to provide the rewards or penalties. The difference between allowing 80% verses 90% can be substantial in terms of dollars, and the justification of the selection of the target using "reasonableness" or "fairness" may be seen as very subjective or judgmental.

The partial pass-through of fuel costs in the RSP is an option the Board may wish to consider. In considering this modification the following issues should be addressed:

- impact of partial pass-through on financial stability of Hydro;
- opportunity for Hydro to manage fuel costs and therefore effectiveness of partial pass-through as an incentive mechanism;
- process and methodology for establishing targets, bands and sharing percentages considering the perceived subjectivity of these items.

Methods used by Regulated Utilities in Other Jurisdictions

As part of this discussion paper, we reviewed several other regulated utilities to determine the type of mechanisms that are used in other jurisdictions. It is important to note that the utilities discussed below are not comparable to Hydro's situation. Differences in the market served, the number, size and type of customers, and the mix of generation can all impact the regulatory decisions in these jurisdictions. However, the following information does provide some examples of how energy costs are treated in other jurisdictions.

Avista Utilities

Avista Utilities is a natural gas and electric energy provider with its primary market in five Northwest states. It serves more than 270,000 natural gas customers in Washington, Idaho, Oregon and California, and more than 310,000 electric customers in Washington and Idaho. Approximately 80% of the region's energy needs is met through the use of hydropower and the remaining needs are primarily met with the use of coal.

In June 2002 (Docket No.UE-011595), the Washington Utilities and Transportation Commission "authorized Avista to implement an "Energy Recovery Mechanism" ("ERM") that allows for positive or negative adjustments to the Company's rates to account for fluctuations in power costs outside of an authorized band for power-cost recovery in base rates." This ERM was implemented July 1, 2002. An excerpt from the Settlement Stipulation included in Docket No. UE-011595 is included in Appendix A of this discussion paper.

Under the ERM, 90% of the difference between actual and base power supply costs outside of a $9 million "Company Band" ("Band") will be deferred to the Energy Cost Deferral Balance. The Company will absorb or benefit from the remaining 10%, positive or negative. The Band is plus or minus $9 million on a calendar year basis. The energy cost deferrals under the ERM is calculated on a monthly basis, and the methodology to compute the change in power supply expenses compares the actual and base amounts in accounts defined by FERC that include purchased power, thermal fuel, fuel, and sales for resale. The calculation also includes other specific components specific to this utility (see pg. 5 of Settlement Stipulation). The Settlement also makes reference that "the ERM shall include a retail revenue adjustment to reflect the change in power production expenses recovered through base retail revenues, related to changes in retail load." (Pg. 6 of Settlement Stipulation).

According to the Stipulation, the deferrals shall be allowed to accumulate until a trigger of 10% of the base retail revenue is reached. Based on the rates approved in the Stipulation, the trigger amount is $27.8 million. When the trigger is exceeded the Company shall file a tariff change to implement the surcharge or rebate. The proposed effective date of the tariff change shall provide for a 90 day review and approval process. (Pg. 8 of Settlement Stipulation). Examples of the operation of the ERM are also included in Appendix A of this discussion paper.

Puget Sound Energy, Inc.

Puget Sound Energy, Inc ("PSE") is located in the State of Washington and is also regulated by the Washington Utilities and Transportation Commission ("WUTC"). PSE delivers electricity, natural gas, and energy solutions to more than 1.2 million customers in Washington State. This Company manages a portfolio of energy resources including electricity and natural gas. Approximately 65% of the electricity is purchased and the remainder is produced by its own generating facilities. Much of the electricity produced and purchased comes from hydro generation.

In June 2002, the WUTC as part of Docket No. UE-011570 and UG-011571 (consolidated) approved a "power cost adjustment mechanism" ("PCA") to enhance the Company's financial stability. The settlement terms for the PCA are included in Exhibit A to the Settlement Stipulation, an excerpt from this Settlement Stipulation is included as Appendix B in this discussion paper.

The WUTC noted in its decision that the PCA mechanism should achieve an appropriate balance between risks to customers and risks to utility shareholders. "The PCA would account for differences in PSE's modified actual power costs relative to a power cost baseline. The mechanism would account for a sharing of costs and benefits that are graduated over four levels of power cost variances, with an overall cap of plus or minus $40 million over the four year period July 1, 2002 through June 30, 2006. If the cap is exceeded, any costs and benefits in excess of the $40 million would be shared at a different level of sharing. The factors influencing the variability of power costs included in the proposal are primarily weather and market related." (See Section B (2) of Exhibit A to Settlement Stipulation).

Section B (3) of Exhibit A, included in Appendix B of this discussion paper, outline the sharing proposal for the PCA. The first band is $20 million annually which is either absorbed or retained by the Company. The second band ranges from $20 million to $40 million annually, and the costs and benefits are shared 50% to the Company and 50% to the customer. The third band ranges from $40 million to $120 million annually, and 10% of the cost and benefits go to the Company and 90% to the customer. The fourth band is anything greater than $120 million annually, 5% of costs and benefits to the Company and 95% to the customers.

There is an overall cap for a four year period from July 1, 2002 through to June 30, 2006. As a separate limit, the Company's share of power costs or benefits will not exceed a $40 million cumulative net balance, as calculated based on the sharing bands noted above. If the cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to customers and 1% to the Company. The cap is removed June 30, 2006 and any deferred balances associated with the cap are set for refund or collection at that time.

The customer's share of the power cost variability deferral is described as follows (See Pg.2 of Appendix B - Settlement Terms for the PCA):

- The sharing amounts will be accounted for on an annual basis. The first 12 month period will be the period beginning July 1, 2002 and ending June 30, 2003.

Subsequent PCA periods will be 12 month period beginning on July 1 of each year. The surcharging of deferrals can be triggered by the Company when the balance of the deferral account is approximately $30 million. The Company shall make a filing to refund deferrals when the balance in the deferral account is a credit of $30 million or more.

- To address financial needs and to provide customers a price signal to reduce energy consumption, a surcharge can be triggered when the Company determines that, for any upcoming 12 month period, the projected increase in the deferral balance for increased power costs will exceed $30 million. The surcharge will be implemented through a special filing subject to Commission approval detailing the events giving rise to the projected cost variance.

- In August of 2003 and each year thereafter, the Company shall file an annual report detailing the power costs included in the deferral calculation, in a form satisfactory to the Commission, for Commission review and approval. The Commission shall have an opportunity to review the prudence of the power costs included in the deferred calculation, and costs determined to be imprudent can be disallowed at that time. Staff and other interested parties will have the opportunity to participate in the prudence review process. The Company will also provide the Commission with a quarterly report of the deferral calculation in a form satisfactory to the Commission.

- Unless otherwise determined by the Commission, surcharges or credits will be collected or refunded, as the case may be, over a one year period. If for any reason the PCA shall cease to exist, any balances in the deferred accounts not previously reviewed will be reviewed and set for refund or surcharge to customers at that time.

The elements of the PCA are described in Section C of the Settlement Terms which are included in Appendix B of this discussion paper.

Idaho Power Company

Idaho Power is involved in the generation, purchase, transmission, distribution and sale of electric energy in a 20,000 square mile area in southern Idaho and eastern Oregon with an estimated population of 814,000. As of Dec. 31, 2002, the Company had 1,688 full time employees and Idaho Power supplied electric energy to 412,203 general customers of which 344,447 were residential customers and 53,779 were commercial and industrial; the remaining 14,082 were irrigation customers. The Company owns and operates seventeen hydroelectric power plants and shares ownership in three coal-fired generating plants. Idaho Power relies heavily on hydroelectric power for its generating needs.

The Idaho Public Utilities Commission regulates the Idaho Power Company ("IPC") and in 1993 the Commission authorized the IPC to adopt a Power Cost Adjustment mechanism ("PCA"). In an application filed by the Company on November 24, 1992, IPC argued that its current system of normalization does not work (see further details in Appendix C of this discussion paper). The Company explained that "during extended periods of low water the Company's earnings can suffer significantly, resulting in cash flow problems which place constraints on the Company's operations and maintenance and capital expenditures. The low earnings during extended periods of drought also place the Company at risk of a poor rating by financial analysts, thereby increasing the cost to Idaho Power when it must enter the capital markets for financing.

The Company indicated that the best means of addressing the variability in its power supply costs is to replace normalization with a PCA that compensates for that variability and this type of mechanism would greatly stabilize Idaho Power's earnings. The Company also noted that ratepayers would also benefit from such a mechanism when stream flows are high and rates are adjusted downward. For the purposes of this application, the Company defined PCA costs (which are largely influenced by stream flows) as: Fuel costs + non-firm purchases + cogeneration, small power production (CSPP) costs - non-firm revenue - FMC secondary revenue. (Pg. 4 of 19, Order No.24806, The Idaho Public Utilities Commission).

The mechanism was approved with the following basic elements: "It is based on annual forecasted power supply costs; deviations from predicted annual power supply expense are deferred and trued-up in a subsequent year; interest is accrued on deferrals; an efficiency incentive shares variations in power supply costs from a base case between the ratepayers and the Company on a 90-10 ratio; a procedure to guard against rate shock is included; power supply costs associated with changes in load are factored out of the PCA; rate changes mandated by the PCA are recovered by an equal cents per kilowatt hour allocation, and; proposed changes to the FMC rate structure are approved." (Pg.3 of 19, Order No. 24806, The Idaho Public Utilities Commission)

During the hearing, forecast based PCA's and deferred accounting PCA's were proposed in the case. In their findings, the Commission indicated that a forecast-based PCA with a true-up was most appropriate for IPC. They said that a forecast most closely matches costs to the time period in which they were incurred, which sends the more appropriate price signal to ratepayers Under the deferred accounting PCA's proposed, they said it would be possible that rates would not be adjusted until years after the costs which caused the adjustment had been incurred.

In the conclusion of this Order, the Commission noted that:

> "In this proceeding we have been required to balance and reconcile conflicting but valid objectives with respect to the proper design of a power cost adjustment mechanism. The PCA we adopt today will provide earnings stability for the Company in low water years and will provide ratepayer benefits in high water years through reduced rates. Recognizing that these benefits come at the expense of the goal of rate stability, we have included provisions to alleviate rate shock. We have also adopted measures to improve the accuracy of the forecast model.
>
> Notwithstanding this, we recognize that any forecast will have some degree of inaccuracy and we have included provisions to ameliorate these predictive inaccuracies." (Pg. 18 of 19, Order No. 24806, The Idaho Public Utilities Commission).

For further details and discussion on this mechanism, refer to the Order No. 24806 in Appendix C of this discussion paper.

Summary

As noted in the introduction, the scope of our review is to provide a report which will serve as a discussion paper on Hydro's RSP. We have reviewed a number of issues relating to the operation of the RSP as raised during the 2001 Rate Hearing. As part of this review we have identified and discussed several modifications to the RSP which the Board may wish to consider further. We would expect that any further consideration would include input from Hydro and the various stakeholders on the issues and modifications discussed.