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December 4, 2017

Via Email & Courier

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

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: 2017 General Rate Application – Expert Evidence Report

Enclosed please find an original and thirteen (13) copies of the Expert Evidence Report of JT Browne Consulting which provides an assessment of Hydro's proposed Off-Island Purchases Deferral Account giving consideration to established regulatory principles.

If you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Senior Counsel, Regulatory

TLP/skc

cc: Gerard Hayes - Newfoundland Power
Paul Coxworthy - Stewart McKelvey Stirling Scales
Denis J. Fleming - Cox & Palmer
Dennis Browne, Q.C. - Consumer Advocate
Dean Porter - Poole Althouse

ecc: Van Alexopoulos - Iron Ore Company
Senwung Luk - Labrador Interconnected Group
Benoît Pepin - Rio Tinto

JTBrowne
Consulting

Newfoundland & Labrador Hydro

Off-Island Purchases Deferral Account

December 4, 2017

Costing &
Regulatory Consulting

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INTRODUCTION

Newfoundland and Labrador Hydro ("Hydro") is proposing to create a deferral account that would be referred to as the "Off-Island Purchases Deferral Account" ("OPDA").

The OPDA would collect and defer the net specified benefits associated with the Muskrat Falls Project ("MFP") prior to the commissioning of the Muskrat Falls Generating Facility ("MFGF"). It is expected that the balance in the account would be used to reduce rates after the MFGF is commissioned; however the disposition of the account would be determined by the Board of Commissioners of Public Utilities ("Board") at a future date.

Hydro has asked me as a CPA, CA and economist with experience in addressing regulatory issues[1] whether the OPDA is consistent with established regulatory principles.

In developing my opinion I have relied on information about Hydro, the MFP and the OPDA that was provided to me by Hydro. I was not asked to verify this information and did not undertake the work necessary to provide a professional opinion on the validity of the information.

The next section of this report sets out information relevant to the development of my opinion. This is followed by a discussion of relevant regulatory principles and an analysis of the OPDA. The last section sets out my opinion.

[1] A copy of my resume has been attached as Appendix JTBC-1.

BACKGROUND[2]

The OPDA would deal with certain net benefits associated with the MFP that may arise prior to the full commissioning of the MFGF ("Pre-commissioning Net Benefits").

MUSKRAT FALLS PROJECT

The MFP is being undertaken to enable Hydro to obtain a long-term supply of hydro power from Labrador for the Island Interconnected System ("IIS"). The MFP is comprised of three components: MFGF, the Labrador Transmission Assets ("LTA"), and the Labrador-Island Link Transmission Assets ("LIL"):

- The MFGF is a hydro generating facility located at Muskrat Falls on the Churchill River in Labrador. In addition to providing power for Hydro, the facility will provide power for Emera, and if surplus to Hydro's IIS needs, other potential customers.

- The LTA will provide a transmission link between the MFGF and the Churchill Falls Generating Facility ("CFGF"). This intertie will permit the coordination of production between MFGF and CFGF. It will also connect to the LIL. Through this connection it will also allow Hydro access to the North American Grid through Quebec, allowing further options to acquire power, and possibly even sell power.

- The LIL will provide a transmission link from the MFGF and the LTA to Hydro's transmission facilities on the IIS.

In addition, Emera is building the Maritime Link ("ML") to connect the IIS to Nova Scotia and the North American Grid through Nova Scotia. This will allow power from Newfoundland and Labrador to be transported to Nova Scotia and beyond; it will also allow Hydro to acquire power from the mainland through Nova Scotia. It appears to be unlikely that the ML would have been built at this time without the MFP.

AGREEMENTS

Hydro has entered into two agreements that set out its payments for the MFP: the Muskrat Falls Power Purchase Agreement ("MF PPA"), and the Transmission Funding Agreement ("TFA"). The MF PPA is with Muskrat Falls Corporation ("MFCo"), and the TFA is with Labrador-Island Link Operating Corporation (LIL Opco); both companies are affiliates controlled by Nalcor:

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[2] As previously discussed, I was not asked to verify this information and did not undertake the work necessary to verify it.

- The MF PPA is a long-term agreement that begins when the first generating unit of the MFGF and the LTA come into service, and ends 50 years after full commissioning of the MFP. Under this agreement, Hydro has the right to specified amounts of power from MFCo. In return, Hydro is required to make payments to MFCo in accordance with terms specified in the agreement.

- The TFA is a long term agreement that begins upon full commissioning of the LIL and is expected to extend for about 50 years. Under this agreement, Hydro is required to make payments to LIL Opco in accordance with terms specified in the agreement. In return, the Newfoundland and Labrador System Operator ("NLSO")[3] will treat the payments as credits against Hydro's payment obligations arising under any transmission service agreements to which Hydro may be a party. These service agreements will cover usage of the LIL and LTA.

In the case of the above agreements, the Lieutenant Governor in Council ("Government") provided specific directions to the Board for the recovery of costs. The Government set out requirements that cover essentially any expenditures, payments or compensation paid directly or indirectly by Hydro and related to the MFP. These amounts must be included in Hydro's cost of service, without disallowance, to be recovered through IIS customer rates, with two exceptions:

- The amounts must not include amounts directly attributable to the marketing or sale of power by Hydro to non-Island customers on behalf of MFCo.

- None of the amounts are to be included in customer rates until the MFP is commissioned, or nearing commissioning, and Hydro is receiving services from the MFP.

IMPACT OF MFP ON RATES

With the full commissioning of the MFP, Hydro is expecting a significant increase in rates. Per kilowatt hour (kWh) before HST, average island residential electricity rates are expected to increase from 11.7 cents in 2017 to 22.89 cents in 2021. Most of the increase will be due to the MFP.

The current Government has indicated that export sales will be used to mitigate potential increases in electricity rates, thereby reducing the above increases. Even if this is the case, it is expected that rates will be significantly higher than what they would otherwise be, at least for the foreseeable future.

Although the MFP will require significantly higher rates, the MFP may produce net benefits for Hydro and its customers prior to full commissioning. The MFGF is not

[3] The NLSO is a functionally separate part of Hydro.

expected to be fully commissioned until September 1, 2020; however, the LTA and the LIL are expected to be completed and available to provide service by July 1, 2018. This will allow Hydro to purchase some of the Recapture Power from CFGF at 0.2 cents per kWh before transmission costs, and possibly acquire other power that would be transported to the IIS over one or both of the LIL and LTA. This purchased power will allow Hydro to reduce the power produced at Holyrood and the cost of fuel used to produce that power.

In addition, Hydro will be able to acquire the pre-commissioning power from MFGF (i.e., power produced prior to full commissioning) at no cost before transmission costs, resulting in further potential reductions in power produced at Holyrood.

Even with the charges from MFCo and LIL Opco for the use of the LTA and the LIL, it is expected that the cost of acquiring Recapture Power and pre-commissioning power from MFGF will be less than the associated savings from producing less power at Holyrood (i.e., savings in the cost of fuel) prior to the full commissioning of the MFGF. Hydro's estimate of these net benefits is presented in Table 1.

It should be noted that the actual net savings could vary significantly from any estimates used in setting rates due to factors that are largely outside the control of Hydro. They could vary due to the completion date of the LTA and the LIL, the availability of Recapture Power, the amount of pre-commissioning power from the MFGF, the charges from LIL Opco, the amount of fuel saved as result of the power from Labrador and the estimated cost of that fuel.

The completion of the LTA, the LIL and the ML will provide Hydro with the opportunity to purchase additional off-island power, and so further reduce the power produced at Holyrood prior to the commissioning of the MFGF (the ML is expected to be completed by January 2018). Since it is unlikely that the ML would have been built at this time without the MFP, Hydro views any net savings as a result of the ML prior to the commissioning of the MFGF to be an integral part of the net benefits/costs of the MFP.

Hydro has been exploring additional off-island power purchases that may be available as a result of the LTA, LIL and ML, and that would provide net benefits. However at this time, Hydro does not have an estimate of these potential net savings. Moreover any estimates could vary significantly from the resulting actual net savings due to factors outside the control of Hydro. For example, the actual net saving would depend on factors such as: the market price of power at the time Hydro purchases the power; the purchase terms that may be available and that could affect Hydro's ability to reduce production at Holyrood; and the price that Hydro pays for the fuel used at Holyrood.

The net benefits prior to full commissioning of the MFGF would also include improved reliability of the IIS. It would be difficult to estimate the value of this increased reliability and Hydro has not attempted to estimate it.

OPDA

Hydro is proposing to create the OPDA to deal with the uncertainty in estimating the Pre-commissioning Net Benefits.

In the absence of the OPDA, Hydro would estimate the amount of power it would acquire from Labrador or through Nova Scotia ("Off -Island Purchases"), along with the associated unit costs. These estimates would be used to estimate:

- the amount of power produced at Holyrood and the associated cost of fuel to be included in Hydro's revenue requirements;
- Hydro's average fuel inventory, the associated impact on its cash working capital, and the resulting impact on its allowed return included in its revenue requirements; and
- the cost of Off-Island Purchases that would be included in its revenue requirements.

The actual amount of Off-Island Purchases, the cost of those purchases, the impact of those purchases on the power produced at Holyrood, and the cost of fuel that would have been necessary to produce that power could vary significantly from the estimates required in establishing Hydro's revenue requirement. These variances would be largely outside its control. Therefore, Hydro is proposing to collect and defer the impact of the Off-Island Purchases prior to the full commissioning of the MFGF – i.e., the Pre-commissioning Net Benefits. The deferred amounts, plus a return of the deferred amounts, would be used to reduce future revenue requirements

The eventual disposition of the OPDA would be determined by the Board at some time in the future. However, Hydro expects that it might be used to help phase in the increase in rates required by the MFP.

The net credit to the OPDA would be calculated as follows:

- (actual Off-Island Purchases in kWh) divided by (test year estimate of the amount of fuel required to produce a kWh at Holyrood) times (test year estimate of the cost of fuel used by Holyrood); plus
- ({test year estimate of average fuel inventory} minus {actual fuel inventory}) times (test year estimate of the cost of fuel used by Holyrood) times (test year estimate of Hydro's weighted average cost of capital); minus
- Actual cost of Off-Island Purchases including the cost of using the LTA and the LIL.

Table 1 sets out Hydro's estimated net credit to the OPDA and its year-end balance in the period 2018 through 2020.

EXPECTED IMPACT OF OPDA ON REVENUE REQUIREMENTS

Table 2 sets out Hydro's estimate of the impact of the OPDA on its revenue requirements for the IIS in 2018 and 2019.

As indicated by Table 2, the OPDA will have a material impact on Hydro's revenue requirements, with the OPDA increasing Hydro's revenue requirement for the IIS by 13.7% in 2019. However, this would not mean a 13.7 % increase in rates. Without the ODPA, Hydro would have a 7.8% decrease it revenue requirements for the IIS in 2019. This would likely increase the rate increase required once the MFP is commissioned, thereby reducing rate stability.

Table 1

OPDA ESTIMATED NET CREDIT & BALANCE 2018 THROUGH 2020 ($,000)			
	2018	2019	2020
Fuel Cost Savings	40,454	129,934	109,601
Impact on Return From Lower Fuel Inventory	43	169	2,541
	40,497	130,103	112,142
Cost of Off-Island Purchases			
Recapture Power	886	1,946	260
OpEx LTA/LIL	27,300	52,900	35,700
	28,186	54,846	35,960
	12,311	75,257	76,182
Return on Average Balance	407	2,860	7,323
Net Credit to OPDA	12,717	78,117	83,504
Net Balance in OPDA	12,717	90,834	174,338

Table 2

OPDA Impact on IIS Revenue Requirements ($,000)		
	2018	2019
Without OPDA	619.1	570.6
Impact of OPDA	12.7	78.1
With OPDA	631.8	648.7
% Increase	2.1%[4]	13.7%[5]

[4] (12.7 / 619.1) = 2.1%

[5] (78.1 / 570.6) = 13.7%

REGULATORY PRINCIPLES

Regulators must review and set rates in accordance with their empowering legislation. However, this legislation seldom contains detailed guidance on how to set rates; it may state little more than that rates must be just and reasonable.

The lack of detailed guidance means that regulatory boards not only have the opportunity to exercise a significant amount of judgment in setting or approving rates, they are required to do so. To assist them in exercising their judgment, they frequently refer to established regulatory principles to guide them in determining what is appropriate in a particular case.

No single authority sets regulatory principles. Instead, principles become established through their general acceptance by regulators; and in some cases, reflect court decisions. Unfortunately, the principles may sometimes be in conflict and trade-offs are required.

In the context of the issue Hydro has asked me to address, the following principles are relevant:

- just and reasonable;
- cost of service standard;
- intergenerational equity; and
- rate stability and predictability.

JUST & REASONABLE

The primary regulatory principle, and the one most likely to be incorporated into regulatory legislation, is that rates should be just and reasonable, or words to that effect. For example:

- The Newfoundland & Labrador "Electric Power Control Act, 1994" states that it is the declared policy of the province that the rates to be charged, either generally or under specific contracts, for the supply of power within the province "should be reasonable and not unjustly discriminatory".[6]

[6] Electrical Power Control Act, 1994; para. 3 (a) (i).

- The British Columbia "Utilities Commission Act" states that, in setting a rate under the Act, the Commission must have due regard to the setting of a rate that is not unjust or unreasonable.[7]

"Just and reasonable" applies to both ratepayers and regulated entities, and it requires a weighting of the legitimate interests of both parties. Unfortunately, "just and reasonable" is a vague and subjective concept. It provides an overall direction to regulators but little specific guidance. As a result, other principles to help define "just and reasonable" have developed and become generally accepted.

COST OF SERVICE STANDARD

At the heart of rate regulation is the cost of service standard, sometimes referred to as the revenue requirement standard. Under this standard, a regulated entity is permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

This standard was recognized in a recent decision of the Supreme Court of Canada:

> *In order to ensure that the balance between utilities' and consumers' interests is struck, just and reasonable rates must be those that ensure consumers are paying what the Board expects it to cost to efficiently provide the services they receive, taking account of both operating and capital costs. In that way, consumers may be assured that, overall, they are paying no more than what is necessary for the service they receive, and utilities may be assured of an opportunity to earn a fair return for providing those services.*[8]

The cost of service standard does not require that a regulated entity be guaranteed a fair return, only that it have an opportunity to earn it. In most cases, rates are set prospectively, based on estimated future costs: if the entity over-recovers, it normally keeps the excess; if it under-recovers, it bears the deficiency.

The opportunity to earn a fair return implies that the possibilities of under and over-earning are offsetting. Using more technical language, allowed rates should provide an expected rate of return equal to the fair rate of return, where the expected rate of return is equal to the average of the possible rates of return weighted by the probability of their occurrence.[9]

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[7] Utilities Commission Act, [RSBC 1996] Chapter 473; para 60 (1) (b) (ii).

[8] Ontario (Energy Board) v. Ontario Power Generation Inc.; 2015; SCC 44; para. 20.

[9] For example, if there is a 40% probability of an 8% return, and a 60% probability of a 12% return, the expected return is 10.4%: (8% x 40%) + (12% x 60%) = 10.4%.

The cost of service standard is consistent with what is expected to occur in a competitive market, where the prices for goods and services tend to equal the cost of providing them, including a fair return. This is important since it is often argued that rate regulation is a proxy for competition[10] and it tends to be withdrawn where there is adequate competition to protect ratepayers.

The standard also reflects fairness and the necessity to offer adequate incentives for providing regulated services:

- In fairness, an entity's investors should have the opportunity to recover their costs, including a fair return, just as they would if they were to invest in a non-regulated entity of similar risk. However, ratepayers should not have to provide investors with the opportunity to earn more than they could expect from investing in non-regulated operations of similar risk.
- From an incentive viewpoint, unless investors have a reasonable opportunity to recover their costs, it will be difficult to attract the investment necessary to provide regulated services. However, the opportunity to recover costs, including a fair return, should provide an adequate incentive to attract those funds.

The cost of service standard is applicable to all regulatory methodologies, including performance-based methods such as price cap regulation. A regulated utility may earn more or less than a fair return, and performance based methods increase the possibility of realized earnings deviating from a fair return. However, the issue is that a regulated entity should have a reasonable opportunity to earn a fair return.

INTERGENERATIONAL EQUITY

The principle of intergenerational equity deals with how the cost of service should be recovered from ratepayers. Under this principle, ratepayers in a given period should pay only the costs necessary to provide them with service in that period. They should not have to pay for any costs incurred to provide service to ratepayers in another period. This principle is consistent with setting just and reasonable rates within each period.

For example, a regulated entity is usually not allowed to earn a return on projects under construction. It's incurring this cost to provide service to future ratepayers, not ratepayers in the current period. Instead, the return is capitalized and recovered through depreciation over the period in which the assets are used to provide service.

[10] For example, in a 2001 decision the Ontario Energy Board ("OEB") stated: *The Board notes that the general role of the regulator is to act as a proxy for competition….* (OEB; ; RP-2001-0032; December 13, 2002 para. 5.11.49)

Combined with the cost of service standard, the principle of intergenerational equity requires that rates within a period should cover the costs of providing service in that period, but only that period.

This principle's importance depends on the periods involved. Customers in one year tend to be the same as those in the next, and their relative usage generally doesn't vary that much from year to year. Having customers in one year pay more as a result of costs incurred to provide service in the previous year would not be as serious a breach of this principle as it would be if they had to pay more because of service provided to customers 10 years earlier. In the first case, it is more likely that the costs will be borne by those that benefited from their incurrence, and in proportion to the benefits they received.

If costs can't be recovered in the period for which they were incurred, it's generally best to recover them in a period as close as possible to the one for which they were incurred.

RATE STABILITY AND PREDICTABILITY

Another principle that deals with how the cost of service should be recovered is the principle of rate stability and predictability. It requires rates to remain stable and predictable – at least to the extent practical.

This principle recognizes that it is usually easier for ratepayers to deal with gradual and predictable rate increases. It may justify smoothing out changes in rates to avoid sharp rate climbs or temporary fluctuations.

The principle's intent is to establish only when costs are recovered, not the amount actually recovered. In practice, it does affect the amounts recovered because the timing of cost recovery affects financing costs. Where costs are deferred, the deferred amount must be financed, and regulated entities are entitled to recover the additional financing costs under the cost of service standard.

The principle of rate stability and predictability may require costs to be collected from ratepayers in periods other than those for which they were incurred. Therefore, it is inconsistent with the principle of intergenerational equity. Despite that, it may be justified because it recognizes the adverse consequences where ratepayers must adjust to significant rate increases or short-term rate fluctuations.

As time passes, the makeup and usage of a customer group changes. Therefore, the longer the period that costs are deferred, the more serious the breach of the intergenerational equity principle. As a result, when the principle of rate stability and predictability is applied, cost deficiencies should be recovered over as short a period as is reasonable, so the customer group that eventually pays for the costs is similar to the one benefiting from the costs. Similarly, if to avoid a sharp rate increase, costs are recovered before a period for which they will be incurred, the intervening period should also be as short as reasonably possible.

ANALYSIS OF OPDA

The primary reason Hydro is proposing the OPDA is to deal with the uncertainty in estimating the Pre-commissioning Net Benefits. In addition, the OPDA will enhance intergenerational equity, and rate stability and predictability.

In dealing with uncertainty, deferral accounts provide benefits to both utilities and their customers. These accounts are consistent with the cost of service standard but are often in conflict with the principle of intergenerational equity and rate stability and predictability. Therefore, the evaluation of deferral accounts must usually weigh the benefits of the account against the impact on intergenerational equity, and rate stability and predictability. However in the case of the OPDA, the account will enhance both intergenerational equity and rate stability and predictability.

UNCERTAINTY DEFERRALS

The use of deferral accounts to deal with uncertainty is a common regulatory practice, and such accounts have previously been approved by the Board. Appendix JTBC-2 sets out further examples of deferral accounts that have recently been used to deal with uncertainty.

With these accounts, specific amounts that would normally be included in determining the revenue requirements of a period[11] are instead deferred and included in the deferral account. The balance in the account is then included in determining the revenue requirements or a future period or periods. In some cases, the full amount is deferred; while in others, an estimate of the amount is included in the determination of revenue requirements and the difference between the actual and estimated amount is deferred (such deferral accounts are often referred to as variance accounts).

The deferred amounts will affect a utility’s cash flow and funding requirements, and therefore its cost of capital. As a result, an estimate of this impact on the utility’s cost of capital is debited or credited to the deferral account and included in the amortization of the account.

Where deferral accounts are used, the amounts deferred are usually largely outside the control of the utility. Normally, rates are based on expected costs and the utility keeps whatever income (or loss) that results from those rates. Utilities therefore have an incentive to control their costs so as to increase their income. However, where actual amounts are deferred and included in the determination of future revenue requirements, that incentive is lost. Where amounts are outside the control of management, a utility cannot affect the amounts and incentives are irrelevant.

[11] The amounts deferred might include costs, cost savings, revenues, gains, or losses.

In the case of the Pre-commissioning Net Benefits, Hydro will have limited control. For example the completion date of the LIL, LTA and ML are outside its control, as are the charges from MFCo and LIL Opco.

BENEFITS OF DEFERRAL ACCOUNTS TO DEAL WITH UNCERTAINTY

With a deferral account, there is no need to make an estimate of the deferred amount. The amounts are used in determining revenue requirements only after they are know.

This eliminates the effort and cost necessary to estimate the deferred amount; including a reduction in hearing time and the possible cost of experts who may be hired to debate the estimates. It also eliminates the need for boards to evaluate evidence that is not only inconclusive but may also be contradictory.

As noted above, in some cases an estimate is included in determining revenue requirements, with the difference between the actual amount and the estimate being deferred. Although an estimate is required, the effort and cost that goes in making and debating the estimate will likely be significantly reduced. All parties know that eventually the actual amounts will be included in the determination of rates – no more and no less.

Deferral accounts also eliminate the difference between the estimate that the utility is given an opportunity to recover and the actual amount related to the deferral. This tends to reduce the variability of a utility's earnings, and its under or over recovery of costs.

- The reduced variability in earnings tends to reduce the perceived risk of the utility. This tends to decrease the cost of debt and equity, allow a higher debt ratio, or some combination; thereby reducing the utility's cost of capital that is passed on to customers through allowed rates.

- Where the difference between the actual amount and the estimate results in a significant loss, it may impair the utility's financial integrity. This would affect its ability to acquire the funds necessary to provide regulated service.

- Where there is a material possibility that the difference between the actual amount and the estimate used in setting rates could result in a significant gain, there may be concerns. For example, customers may not like the idea that a utility gets an opportunity to recover a cost that may never materialize.

The benefits of a deferral account depend on both the uncertainty and size of the potential variability associated with the deferred amounts. The greater the uncertainty and size, the greater the benefits of a deferral account. As discussed in the Background section, there is a great deal of uncertainty associated with the Pre-commissioning Net Benefits and the potential variability is material.

COST OF SERVICE STANDARD

The OPDA would be consistent with the cost of service standard:

- The deferred amounts will be included in determining revenue requirements, but only once. They will not be considered in setting rates in the period in which they are deferred; instead they will be included in the determination of revenue requirements in a future period or periods in which the OPDA is amortized.

- The amounts deferred in the OPDA would reduce Hydro's funding requirements and its financing costs. To recognize this, the OPDA would be credited with an amount equal to the savings in financing costs (i.e., average balance in OPDA times Hydro's WACC) and these amounts would be added to the OPDA and used to reduce future revenue requirements.

Therefore, the OPDA will not affect Hydro's opportunity to recover its costs of providing regulated service.

INTERGENERATIONAL EQUITY

Deferral accounts are usually in conflict with the principle of intergeneration equity: they take amounts that should be included in determining the revenue requirements of one period and include them in determining the revenue requirements of another. However, unlike most deferral accounts, the OPDA would enhance intergenerational equity.

Prior to full commissioning, the MFP will provide net benefits to Hydro and its customers; however, after full commissioning, there will be a significant increase in Hydro's cost of power and the rates it charges its customers. The Pre-commissioning Net Benefits are an integral part of the MFP and would not occur without it. Therefore intergenerational equity would require that the Pre-commissioning Net Benefits be deferred and amortized after full commissioning of the MFP. In this way, the future customers who have to bear the increase in costs as result of the MFP get the net benefits of the project prior to commissioning.

Even if this were not the case, it would enhance intergenerational equity to defer the Pre-commissioning Net Benefits until the MFP is "commissioned or near commissioning". In order to acquire power using the LTA or the LIL, Hydro will have to pay amounts to MFCo and LIL Opco. The Board is required to allow Hydro the opportunity to recover these amounts through its regulated rates; however, this cannot happen until the MFP is "commissioned or near commissioning".

It would be contrary to the principle of intergenerational equity to pass on to customers of one period benefits included in the Pre-commissioning Net Benefits, while a significant amount of the associated costs were borne by customers of a later period.

RATE STABILITY AND PREDICTABILITY

Deferral accounts can reduce rate stability and predictability. Amounts related to the period over which amounts are deferred are added to, or deducted from, the revenue requirements over the recovery period. Where material, this can result in increased variability in rates. In extreme cases it can result in an increase (decrease) in rates followed by a decrease (increase) in rates.

As discussed in the Background section, the OPDA is expected to increase rates relative to what they would otherwise be in the period prior to full commissioning of the MFP. This will help to smooth out the increases necessary to accommodate the MFP. Moreover, the amortization of the OPDA may be used to further smooth rates once the MFP is commissioned.

CONCLUSION

The OPDA would be a deferral account created to deal with the uncertainty associated with the Pre-commissioning Net Benefits.

The use of deferral accounts to deal with uncertainty is a common regulatory practice that provides benefits to utilities and their customers. The accounts eliminate the effort and cost to estimate the associated deferred amount. They also eliminate the difference between estimates used in determining revenue requirements and the actual amounts. This tends to reduce a utility's cost of capital that is passed on to customers; reduces the possibility that a utility will have losses that might impair its financial integrity and its ability to raise the funds necessary to provide regulated service; and reduces the possibility that estimates used in setting rates could significantly exceed actual amounts which may create concerns for some customers.

The benefits of a deferral account depend on both the uncertainty and size of the potential variability associated with the deferred amounts. Also, where a utility has control over the deferred amount, a deferral account would reduce the incentive to manage the cost. Therefore, deferral accounts tend to be used only where there is significant uncertainty as to the deferred amount, the potential variability in the deferred amount is material and the amount deferred is largely outside the control of the utility. As discussed in the Background section, the amounts to be deferred with the OPDA meet these conditions.

Deferral accounts are normally consistent with the cost of service standard but inconsistent with intergenerational equity and possibly rate stability and predictability. As a result, there is often a need to weigh the benefits of a deferral account against the associated impact on intergenerational equity and rate stability and predictability. However, in the case of the OPDA, intergenerational equity and rate stability and predictability would be enhanced.

OPINION

Based on information provided to me by Hydro and summarized in this report, the Proposed OPDA as described in this report would be consistent with established regulatory principles.

The proposed OPDA will provide benefits to Hydro and its customers by including the actual amount of the Pre-commissioning Net Benefits in the determination of Hydro's future revenue requirements:

- The OPDA would reduce the effort and cost in estimating the Pre-commissioning Net Benefits;
- tend to reduce Hydro's cost of capital;
- reduce the possibility of losses that might impair Hydro's financial integrity; and
- reduce the possibility that actual net benefits may exceed the estimated net benefits used in determining rates by a material amount, which may be of concern to customers.

The OPDA would also be consistent with the cost of service standard, the principle of intergenerational equity, and principle of rate stability and predictability.

RESUME - JOHN T. BROWNE

Summary:

John Browne has been assisting clients in applying regulatory principles and resolving financial, accounting and costing issues related to rate regulation for over 30 years. Prior to establishing his own practice 18 years ago, he was a consultant with Deloitte and Touche LLP, the last seven years as a partner.

He has directed and worked on a wide range of studies for rate-regulated entities that have dealt with accounting and cost allocation principles, the determination of rate base, cost of service determination, product costing/pricing, rate of return, capital structure, and methods of regulation.

He has appeared as an expert witness on accounting, costing and financial issues before the following regulatory tribunals: Canadian Radio-television and Telecommunications Commission, Canadian Transport Commission, the Alberta Public Utilities Board / the Alberta Energy and Utilities Board, the Manitoba Public Utilities Board, Newfoundland and Labrador Board of Commissioners of Public Utilities and the Nova Scotia Board of Commissioners of Public Utilities.

Education / Professional Qualifications:

- Bachelor of Commerce - Queen's University
- Master of Arts (Economics) - Queen's University
- Chartered Professional Accountant, Chartered Accountant

Committees/ Publications

Mr. Browne was Chairman of the Canadian Institute of Chartered Accountants (“CICA”) Study Group that produced the CICA research report “Financial Reporting By Rate Regulated Enterprises”.

He authored or co-authored the CA Magazine articles “A Matter Of Principles - Part I” “A Matter Of Principles - Part II” and "Regulatory Assets". These articles dealt with accounting by rate-regulated enterprises.

He co-authored the Deloitte & Touche publication “Basics of Canadian Rate Regulation” and authored the Deloitte & Touche monograph “The Contractual Pitfalls of Relying on GAAP”. He has also authored a number of papers for distribution to clients and potential clients such as “Fundamentals of Rate Regulation” (an update of “Basics of Canadian Rate Regulation”) and “Comments on Deferral Accounts to Deal With Uncertainty”.

Key Clients: Mr. Browne's major clients have included: Newfoundland Power Inc., Nova Scotia Power Inc., New Brunswick Power Corporation, Hydro Quebec, Ontario Hydro, Manitoba Hydro, SaskPower, Edmonton Power, Ottawa Hydro, Canadian Electricity Association, Ontario Energy Board, Atco Gas, Enbridge, Newfoundland Telephone Company Ltd., Bell Canada, Manitoba Telephone System, Saskatchewan Telecommunications, AGT/TELUS, Teleglobe, Telesat Canada, Southwestern Bell Telephone Company, New York Telephone, The Telecommunication Authority of Singapore and Dhiraagu (Maldives).

Selected Assignments:

- Completed a survey of Canadian regulators to determine what they viewed as their objectives and how they interpreted those objectives.

- Assisted Ontario Hydro Services Company (currently Hydro One), one of the successor companies of Ontario Hydro, in understanding its regulatory options by researching and providing advice on a number of regulatory issues related to transfer pricing, structural organization, accounting for income taxes, relationships with affiliated companies, performance-based regulation, etc.

- Participated in the in the OEB consultation process dealing with the transition to IFRS. As part of this participation, made a presentation on proposed principles to guide the development and maintenance of regulatory accounting policies (RAP) and a framework for evaluating proposed changes in RAP.

- Advised the Canadian Electricity Association in the preparation of a paper dealing with the recognition of regulatory assets and liabilities. The assistance included organizing and drafting the report and advising on issues covered in the paper.

- Prepared a draft for the framework and principles section of a utility’s cost manual.

- Researched and analysed the issue of a deferral plan for the introduction of a new plant into rate base. Prepared evidence on the issue for Nova Scotia Power and appeared as an expert witness. Subsequently prepared evidence and appeared as an expert witness on changes to the deferral of the costs on the plant due to changes in circumstances.

- Researched and analysed the issues of phase-in and risk sharing for Edmonton Power's Genesee plant and prepared a recommendation that was submitted to the utility's regulator. Expert testimony was also provided.

- Researched, analysed and presented a recommendation that an electric utility should be allowed to defer tax costs so that the utility could avoid a rate increase followed by a rate decrease.

- Provided a written opinion for Nova Scotia Power on its regulatory treatment of amounts related to an income tax dispute. The report dealt with past taxes that had not been recovered in allowed rates, future taxes that may not be payable, and the use of deferral accounts.

- Prepared a report for Nova Scotia Power Inc. that addressed the utility's plan to use market-related value in determining its pension expense. This plan would result in smoothing the impact of pension expense on rates. The report provided an opinion on whether the plan was consistent with generally accepted accounting principles and established regulatory principles.

- Provided a written opinion for Newfoundland Power on accounting and regulatory issues related to future employee benefits and the company's hydro production equalization reserve. The opinion was included in the company's rate submission.

- Advised New Brunswick Power Distribution and Customer Service Corporation on regulatory issues related to a proposed fuel deferral account.

- Prepared two reports for NSPI: the reports addressed the recovery of unrecovered costs of a retired generating station. The utility's proposal included the recognition of a deferral account for both the unrecovered costs and the related capitalized financing costs.

- Provided a written opinion on a proposal by a not-for-profit electric system operator to deal with surpluses and deficits. In preparing the opinion, the treatment of surpluses and deficits by other not-for-profit independent electric system operators was reviewed.

- Analysed the issue of the appropriate accounting and regulatory treatment of Nova Scotia Power's defeasance program. Prepared evidence and appeared as an expert witness on the issue.

EXAMPLES OF UNCERTAINTY DEFERRALS

It is a common regulatory practice to use deferral accounts to deal with uncertainty. The following represent a sampling of such accounts as reported in the recent financial statements of Canadian utility companies,[1] The quotes come from the notes to the financial statements dealing with regulatory assets and liabilities.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY ("BC HYDRO")

BC Hydro has a deferral account to deal with foreign exchange gains and losses:

> *Foreign exchange gains and losses from the translation of specified foreign currency financial instruments are deferred. Foreign exchange gains and losses are subject to external market forces over which BC Hydro has no control. The account balance is amortized using the straight-line pool method over the weighted average life of the related debt.*[2]

FORTISALBERTA INC

FortisAlberta has an "A1 rider deferral" to deal with the differences between the actual and estimated cost of certain taxes:

> *This balance represents the difference between the A1 rider revenue, which is the collection of linear taxes from customers in current rates based on municipality, and the actual linear tax incurred that is expected to be collected from customers in future rates. To the extent that the amount of revenue collected in rates for these items does not exceed actual costs incurred, the difference is deferred as a regulatory asset to be collected from customers in future rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded to customers in future rates. This balance is not subject to a regulatory return.*[3]

THE MANITOBA HYDRO-ELECTRIC BOARD ("MANITOBA HYDRO")

Manitoba Hydro has purchased gas variance accounts to deal with the differences between the actual and estimated cost of gas:

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[1] The financial statements may not explicitly state that the deferral account was created to deal with uncertainty; however, the description of the account indicates that this is likely the case.

[2] British Columbia Hydro and Power Authority 2016/17 Annual Service Plan Report; pg. 67.

[3] FortisAlberta Inc. Financial Statements For the years ended December 31, 2016 and 2015; pg. 15.

> *Purchased gas variance accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates charged to customers as approved by the PUB. Purchased gas variance accounts are reflected as a regulatory debit or credit depending if the amounts represent a recovery from or a refund to the customers, respectively.*[4]

TORONTO HYDRO CORPORATION ("TORONTO HYDRO")

In discussing its electricity distribution rates in the notes to its 2016 financial statements, Toronto Hydro stated that its regulator (the OEB) may approve the deferral of certain prescribed costs that are eligible for future collection from, or refund to, customers:

> *The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. Under the OEB's rate-setting methods, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.*[5]

Later in the notes to the financial statements, a specific example was described – "Settlement Variances":

> *This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. New variances are accrued based on current charges while approved variances up to 2015, including carrying charges forecasted to the end of 2016, are disposed through OEB-approved rate riders over twelve months commencing on January 1, 2017. Settlement variances pertaining to years subsequent to 2015 have yet to be applied for disposition.*[6][7]

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4 Manitoba Hydro-Electric Board 66th Annual Report for the Year Ended March 31, 2017; pg. 75.

5 Toronto Hydro Corporation 2016 Annual Report; pg. 43.

6 Toronto Hydro Corporation 2016 Annual Report; pg. 51.

7 "LDC" refers to "Toronto Hydro-Electric System Limited", a subsidiary of Toronto Hydro.

GAZ MÉTRO INC. ("GMi")

GMi has rate stabilization accounts to defer amounts due to unpredictable and uncontrollable factors:

> *GMi uses rate stabilization accounts to temper the unpredictable and uncontrollable impact on Gaz Métro-QDA's activities of temperature changes, wind velocity changes and natural gas inventory variances. These RAL are amortized over a two-year period as of the year following their initial recognition. ...*[8][9]

EMERA / NOVA SCOTIA POWER INC. ("NSPI")

NSPI has a "Fuel Adjustment Mechanism" ("FAM") to deal with differences between the actual and estimated amount of certain fuel costs ("Fuel Costs"):

> *... NSPI has a FAM, which enables it to seek recovery of Fuel Costs through regularly scheduled rate adjustments. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year*[10]

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8 Gaz Métro Inc. Consolidated Financial Statements for The Fiscal Years Ended September 30, 2017 and 2016; pg. 90.

9 RAL refers to regulatory assets and liabilities.

10 Emera Inc. - Annual Report 2016, pg. 152.