Manitoba Hydro 2017/18 and 2018/19 General Rate Application

MANITOBA INDUSTRIAL POWER USERS GROUP (MIPUG)
FINAL ARGUMENT
WRITTEN SUBMISSION
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PREFACE

This written submission has been prepared to assist the Board and other parties in navigating the evidentiary record of Manitoba Hydro's 2017/18 and 2018/19 General Rate Application and sets out MIPUG's position on Manitoba Hydro's proposed rate changes and requested approvals.

The written submission includes the following:

- Introduction
- MIPUG Summary of Recommendations
- Background "Issue Papers" addressing the following topics:
    1. Regulatory Signalling and Asymmetry
    2. Unprecedented Financial Framework Achieved Under a 7.9% Rate Projection
    3. Senior Management Expertise and Experience
    4. Change in Underlying Financials Since NFAT and the 2015 GRA
    5. The Benefits of the 7.9%/Year Rate Plan are Overstated
    6. Assessment of the Risks and Impacts of Hydro's Plan
    7. Sufficiency of Current Rates to Cover Current Costs
    8. Is Bipole III Driving the Need for the 7.9% Rate Increase
    9. Regulatory Deferral Accounts
    10. Sustaining Capital
    11. Pessimism in Financial Forecasts
    12. DSM Considerations
    13. Uncertainty Analysis and Future Regulatory Tools
    14. Cost of Service Methods and Customer Service – General (C10)
    15. Rate Design
- References and Legal Authorities

MIPUG recognizes many of these issues are interrelated and cannot be fully appreciated in complete isolation. Therefore this written submission is intended to supplement, but not substitute for, MIPUG's oral argument. MIPUG appreciates the opportunity to prepare and submit these written comments.

To the extent that MIPUG does not expressly reply to an issue raised or position taken by another party to the proceeding, MIPUG should not be taken to agree with the other party's position.

INTRODUCTION

MIPUG is an association of major industrial customers operating in Manitoba belonging to the 3 GSL classes (>100kV, 30-100 kV and 0-30 kV). These customers work together on issues of common concern related to electricity supply and rates in Manitoba. To that end, MIPUG has intervened in each of the Board's reviews of Hydro rates since 1988, as well as the Board's review of the Centra Gas acquisition in 1999,the Hydro's Major Capital Projects in 1990 and the Needs For and Alternatives To (NFAT) review in 2013-2014. MIPUG members currently include:

- Chemtrade Logistics (previously Canexus Chemicals), Brandon;
- ERCO Worldwide, Virden;
- Koch Fertilizer Canada ULC, Brandon;
- Canadian Kraft Paper Inc. (previously Tolko Industries), The Pas;
- Hylife Ltd., Neepawa;
- Maple Leaf Foods Inc., Brandon;
- Gerdau Long Steel North America, Selkirk;
- Amsted Rail - Griffin Wheel Company, Winnipeg;
- Winpak Ltd., Winnipeg;
- Integra Castings (CTD Group), Winkler;
- Enbridge Pipelines Inc., Southern Manitoba;
- TransCanada Keystone Pipeline, Southern Manitoba.

Member concerns are reflective of the size of their investments in Manitoba, the long term view essential for such investments, and the requirement for continued large-scale purchases from Manitoba Hydro. Member concerns also reflect competitive market pressures from selling Manitoba industrial products to external markets, and the need to secure the lowest reasonable costs for power and other production inputs, to offset disadvantages from operating in Manitoba, such as transportation. Mr. Bossons, Chair for MIPUG summarized MIPUG's concerns and the current economic environment during his presentation to the Board on February 1, 2018:

MR. DALE BOSSONS: MIPUG's core focus specifically on electricity rates and the reliability of supply. We are not opposed to rate increases, in fact, we have openly supported rate increases in the past. We recognize the need for reinvestment in Hydro's assets and we applaud their desire to maintain a long-term reliable power supply system.

What is important to MIPUG members is that revenue requirements and rates are based on the true cost and with a long-term outlook to the lifespan of the assets. We desire rates that are fairly distributed across classes. We encourage the inclusion of options to assist energy intensive businesses with mutually beneficial cost mitigation programs such as the curtailable rate program, which is currently capped, and we seek stable predictable energy rates that allow us to manage our business and plan for our futures.

…

And why does any of this matter? It matters because the economic contribution that MIPUG members represent is very important to the province of Manitoba. As mentioned earlier, MIPUG members employ over six thousand (6,000) Manitobans with $345 million in salaries and an additional $72 million in contract labour costs, representing an additional thirteen hundred (1300) jobs. We contribute $223 million in taxes and have invested over $6.4 billion of capital into the province. We are high contributors to the local province's GDP and provide $165 million per year in revenue to Hydro. We are an integral part of the province's economic engine and we help to bring prosperity to our province and its citizens.

…

The impact of these proposed rate increases to our members is potentially game changing. Over the next ten (10) years the difference in costs to the operations of the GSL classes we represent of the proposed 7.9 percent compared to the previous 3.95 percent rate increase that has been brought before this Board is almost $850 million. [T7713-7714]

MIPUG SUMMARY OF RECOMMENDATIONS

The following is a summary of recommendations from the Manitoba Industrial Power Users Group (MIPUG) on the Manitoba Hydro 2017/18 and 2018/19 General Rate Application (GRA).

Summary of Relevant Context for MIPUG's Recommendations

In preparation of the MIPUG recommendations, the following considerations were taken into account.

Manitoba Hydro has record retained earnings, and this balance has been growing each year.

Hydro is concurrently taking on three major projects (Bipole III, Keeyask, and MMTP/GNTL), two of which would each individually be the largest capital project in the Corporation's history. These projects are coming online within a few years of each other. Despite these massive undertakings, Hydro is projected to continue growing its retained earnings during this construction period through 2022, under any rate increase scenario tested.

The projects, particularly Keeyask, are behind schedule. However, this delay, combined with high water that has been experienced in recent years, means that by the time the projects come into service, the Corporation will have a much stronger balance sheet than was anticipated when the plans were first approved. Hydro had expected to have $2 billion in retained earnings (about 8% of capital) when Keeyask came into service instead Hydro now expects to have well over $3 billion (about 12% of capital). This is a significant improvement in financial strength.

As well as being behind schedule, Hydro has also failed to keep the projects within budget. However, Hydro continues to lock in $10 million dollars per day of financing at record low interest rates - much lower than ever anticipated when the decision was made to proceed with the projects. As a result the overall cost profile of the company going forward is almost exactly as projected.

In addition, with each passing year Hydro continues to lock in more and more critical financial variables, like capital costs, so that the overall risk scenario modelling shows an increasingly tightened range of possible outcomes. As a result, many of the worst case scenarios considered when the projects were started are no longer considered possibilities. As recently as the last GRA (IFF14), Hydro had contemplated scenarios that could drive the equity ratio down to minus 6%; the worst scenarios today only drive to positive 5%.

Hydro faces interest rate risk, but increases in interest rates are already built into the forecast. For long-term debt, from the 3% rate faced in 2017, Hydro forecasts interest rates will rise to over 5% and this is already built into forecasts. Of course rates could go higher, but with regular review of Hydro's rates there is ability to react as conditions change, for the better or the worse. Over the last decade, Hydro's forecast of interest rates has consistently been too high, not too low.

On the export side Hydro has completed a transition to a low export price and low natural gas price environment compared to what was seen a decade ago. This has been accomplished while maintaining a positive net income in each year. While obviously this market development is not the preferred outcome, Hydro has taken significant actions to mitigate the impacts to some degree, such as increasing the transmission access to major markets like Wisconsin and Saskatchewan where the ability to make sales was previously very limited. Also, there is a significant side benefit to lower priced export markets, in that Manitoba Hydro's go-forward business case now relies much less than it used to on capturing high-priced exports – there is simply far less downside when exports are priced at 4 cents/kW.h rather than 8 cents/kW.h. This means that when Hydro has the inevitable drought, the lost revenue from curtailed exports and the cost from importing power from external markets (as Hydro will need to do) is significantly reduced. As a result, the estimates of drought cost - the key uncontrollable variable in Manitoba Hydro - have plummeted to levels that are less than 50% of what they were a number of years ago. Recall that this is the foremost reason Hydro establishes reserves.

After the major new projects come into service (as is often the case with very large capital projects, and was fully anticipated in the project business case), the Corporation may take a number of years to return to recording positive net income. Vigilance will be required against using this transition effect as a reason to drive up rates and undermine the very loads that are needed to utilize the power from the new development, as well as grow the Manitoba economy and provide Hydro with the revenues needed to address the new costs arising from these projects. For the same reason (large new surpluses, low export prices) it is necessary to be diligent in setting an appropriate level for conservation (Demand Side Management, or DSM) programming that is not excessive.

As is to be expected, the credit rating agencies have taken note of the debt Hydro is adding. However the same agencies expressed understanding and support of the capital plan when presented to them a number of years ago. As testified by Hydro's experienced senior executives at that time:

> [I]t's always been recognized that the targets may not be obtained during periods of major investment in a generation and transmission system and that ratios will necessarily weaken during those periods of investment.
>
> Credit-rating agencies and other stakeholders are prepared to accept short-term weaknesses in financial ratios due to the investments in revenue-generating assets as long as Manitoba Hydro can demonstrate steady progress towards those targets over the long-term.[1]

At that time, Hydro was clear that "long-term" was consistent with returning to a 75% debt ratio well into the 2030s.

It should be expected that Hydro will continue to attract the agencies' attention - as does any large borrower - until Hydro is through this intensive capital build phase. However, Hydro continues to benefit from the guarantee of the province so that no adverse impacts on Hydro's access to credit are even remotely anticipated.

At the same time as these rate pressures are occurring, Hydro is being assessed a near doubling of the charges and taxes ratepayers must pay to government. The effects of these amounts cannot be overstated. In the case of Keeyask alone, they add to more than 3.3 cents on every kilowatt hour produced (note that Hydro's marginal value for generation, based on updated long-term export markets, is now only 4.23 cents/kW.h). With past Hydro developments, and with current similar developments in other provinces, such government charges are not loaded onto new hydro projects. For example, the vast majority of the Muskrat Falls borrowing will not face debt guarantee fees, and the BC Government recently took action to reduce the government-related charges associated with Site C by 2.6 cents/kW.h.

[1] Testimony of previous CFO, Mr. Darren Rainkie, NFAT Review transcript, March 19, 2014, page 2736.

Summary of Recommendations

MIPUG submits that the evidence has indicated support for the following conclusions and recommends the Board take action in the following areas:

1) Finalize the previous 2 interim rate increases (August 1, 2016 and August 1, 2017) at the 3.36% level.
2) Implement an average rate increase for 2018/19 consistent with 20 year outlook, in range of 3.36% or 3.57% as of August 1, 2018 – 12 months after previous increase.
3) Retain rate setting principles based on:
    a) Progressing towards a 75% debt ratio target over approximately 20 years (e.g., 2035/36) while maintaining rate stability and predictability;
    b) Establishing a relevant modern Minimum Retained Earnings Test (MRET) which would guide the Board as to the need for any more aggressive rate increases, should Hydro's retained earnings levels trend below the cost of a 5 to 7 year drought. Hydro's current retained earnings are well above this level, but the purpose would be to help clearly communicate to all interested parties (including capital markets) about the Board's resolve to ensure Hydro rates remain committed to full cost recovery; and,
    c) Moving towards a more refined uncertainty analysis as set out in Recommendation #13 below.
4) Ensure that for the purposes of setting rates (at this or all future GRAs), the Board requires inclusion of all relevant regulatory standards into any Integrated Financial Forecast (IFF) submitted, including the following:
    a) Use Load Forecasts that apply elasticities consistent with the assumed rate increases (e.g., in the range of 3.36% to 3.57%),
    b) Use export price forecasts that include Hydro's best estimate for the terms and conditions under which it can sell the relevant power into the export markets at the relevant point in time, including appropriate capacity premiums, dependability premiums, and bilateral contracting arrangements,

c) Use a consistent set of interest rate forecasts for all new borrowings, including a consistent assumed Weighted Average Terms to Maturity ("WATM") based on Hydro's best assessment of future treasury activities (including consistency among all rate increase scenarios assessed),

d) Fully pursue O&A expense reductions, including reductions to staffing of 900 positions,

e) Confirm $20 million capitalization of overheads indefinitely, amortized over 30 years,

f) Confirm use of ASL depreciation with no assumed reversion to ELG. Do not explicitly amortize difference – manage through natural attrition,

g) Approach DSM consistent with Integrated Resource Planning – including a lower spend level than assumed in the current IFF, and

h) Direction to only spend the deferred DSM budget of $48.8 million if justified as part of IRP assessment.

5) Incorporate revised C10 allocations in the Cost of Service Study (COS) that do not allocated Customer Service and Distribution related functions to large industrial classes (GSL 30-100 kV and GSL >100kV), as these customer classes do not use the functions, or already incur costs for the same services via the C23 allocator.

6) Set rate increase for industrials (GSL 30-100kV and GSL >100kV) 1-2% lower than average, to address Revenue:Cost Comparison (RCC) Ratio. This should also apply to the GSS Non Demand class.

7) Maintain a 95:105 RCC Zone of Reasonableness for rate-setting purposes.

8) Calculate RCCs based on measured costs (i.e., costs net of export revenues)

9) Direct Hydro to bring forward for the Board's review at the next GRA an optional Time of Use rate for GSL (i.e., a rate that customers can opt in to if they see benefits). Direct that Hydro prepare the rate in consultation with affected customers.

10) Recommend that Government implement a 10 year forgiveness of Capital Tax and Debt Guarantee Fees on the major new projects (Keeyask and Bipole III) from the respective dates of in-service. Use the benefits of any such relief split between the following core objectives:

a) Permit accelerated achievement of longer-term debt ratio targets, and

b) Bring average rate increases over the next number of years to within the range of inflation.

11) Recommend that Government amend the relevant legislation to incorporate the effective provisions of OIC 92/2017 into the rate setting framework for Manitoba Hydro on a permanent go-forward basis, or an alternative mechanism that provides the PUB with "oversight responsibility on capital programming in Manitoba" (Tr: 6125).

12) Direct that Hydro undergo a process for annual financial reviews by the PUB, including the opportunity for informed public input, at least until such time as Keeyask is brought into service. Full GRAs should occur at no longer than 2 year interval periods.

a) For the purposes of the next rate increase (to occur no earlier than August 1, 2019) Hydro should be directed to target a filing in late 2018, as early as can be accommodated to include in financial forecasts the updated information on Keeyask budgets based on learnings from the 2018 construction season. This timeline should also permit Hydro to avoid the need for interim rates, which are problematic for customers and lead to inefficient review processes.

13) Direct Hydro to update and advance the uncertainty modelling to include provisions for rate response, such that future risk scenarios can be run with stipulated assumptions for how rates may be mechanistically modified annually within the model to reflect the conditions unfolding in the model. The Board should direct that Hydro file updated model information by summer 2018, and direct that technical workshop or working group (or equivalent) occur with Board advisors and interest parties to receive input and revise/advance the modelling capabilities and assumptions.

14) Similar to the recent Cost of Service hearing, Hydro should be directed to produce a compliance filing in response to the Board's Order, to generate an IFF scenario consistent with the Board's directions for confirmation by the Board that the directions were appropriately applied. Once confirmed, the procedures and approaches set out in this IFF (e.g., approach to export price forecasting, depreciation, accounting for overheads) should be considered the starting point for preparing future GRA financial forecasts.

MIPUG ARGUMENT-IN-CHIEF

Hydro's application for finalization of two existing interim rate increases of 3.36%, plus a further 7.9% for 2018/19 rests fundamentally on the premise that the "(o)ld financial plan has now failed"[1] and "that there is no longer a willingness to relax the equity ratio for an extended duration of fifteen years before recovering to its 25% minimum equity target."[2] Hydro specifically takes issue with its own previous development plans and financial approach, noting: that the "(o)ld plans were not adequate and far too risky"[3] and that "MH will soon have an unsustainable level of debt" that is "not supportable with rate increases of old plan"[4].

In assessing Hydro's proposal and claims, MIPUG submits the Board must take note of a series of considerations:

1) **The Board cannot avoid the fact that it is assessing a "plan".** Notwithstanding that only one rate increase, not already in rates, of 7.9% is proposed for approval in this proceeding, the mathematical justification for rate increases at this specific 7.9% level is the 10 year trajectory (2026/27) to a 75% debt ratio.

    a. MIPUG's submission on this matter focuses on customer impacts and regulatory signaling, as set out in **Issue Paper #1** appended to this argument.

    b. MIPUG key concern is that the signals sent to customers from a 7.9% increase can only be read to indicate that similar future increases are likely[5], while the signal sent to capital markets from a 20 year focused

[1] MH-64, page 4

[2] Manitoba Hydro June 20, 2017 submission on Interim Rates, page 22.

[3] MH-64, page 4

[4] MH-64, page 4

[5] Per Board Independent Export Dr. Yatchew: "But let's say that this Board accepts 7.9 percent and that the -- an important part of the reasoning of why a 7.9 percent rate would be accepted would be the financial ratio targets of, let's say, that 75 percent debt ratio to be achieved within a specified period of time. Other things being equal, that argument would still apply at the next rate hearing. So, if the Board accepted the financial soundness argument at this hearing, my anticipation would be that it would be difficult to reject that argument in the subsequent rate proceeding.
So that's what I mean by the regulator accepts that argument signals that, yes, this is a target that we want to achieve. We want to achieve that -- those financial ratios and, and therefore, the

increase (e.g., 3.36% or 3.57%) can be informed by Board commentary that the Board is prepared to act in the case of bona fide threats to Hydro's ability to repay.

c. MIPUG's concerns also reflect the fact that Hydro is headed into a period of significant generation surpluses, and building (not undermining) customer load and confidence is critical to financially integrating the new major projects[6].

2) **The plan is a fundamental change to the way in which Hydro is financed.** The result of the 7.9% projection is extraordinary financial performance derived on the backs of ratepayers, entirely inconsistent with any previous financial plan for Hydro at any point in its history.

a. MIPUG's submission on this matter reviews the financial performance Hydro projects under the 7.9% rate increase scenario, as set out in **Issue Paper #2**, appended to this argument.

b. Perhaps the clearest demonstration was provided by Mr. Colaiacovo under cross-examination from Board Counsel when, looking at the degree of positive net income that occurs even under the worst drought on record under Hydro's plan, noted: "(a)nd so I think that begs a bit of a question, because if the point of having reserves is to withstand a drought, why are you actually -- why are your rates so high that during a drought, you're still building your reserves?"[7]

3) **The plan is driven by the change in personnel and attitudes at Hydro, and an overriding focus on capital markets.** This focus on capital markets comes at the expense of all other considerations.

a. MIPUG's submission on this matter is contained in **Issue Paper #3** on Senior Management Expertise and Experience.

customer -- and certainly if I was writing a business plan, I would be putting that as a very serious risk that electricity prices would continue to go up at that kind of a rate. (Tr. 4494-4495)

[6] Per Board Independent Expert Dr. Yatchew: "What I'm saying here is that pricing electricity at high levels if it's higher than necessary, for example, leaves assets underutilized and that's the meaning of the sub-optimality. Let me just finally say that with lumpy assets, you're always going to have a period of time when some portion of them are not being used. They're not being fully used; that's just the reality of bringing on a facility that will be fully utilized a few years down the road, but not yet. So there's al - you're going to have that underutilization problem. The price effect exacerbates that." (Tr:4466 lines 9-16)

[7] Transcript page 5612 line 23 to page 5163 line 3.

b. The key principle reviewed is that Hydro has focused on the confidence of capital markets, consistent with the areas where Hydro has secured its new financial expertise. However, Hydro's previous senior management expertise in Crown Corporations, regulated utilities and financial aspects of capital-intensive businesses has been decimated. With this change comes a significant loss of understanding of regulatory principles, the purpose and role of Hydro's financial targets, proper approaches to balancing customer interests, Hydro's influence on the economy of Manitoba, and the importance of customer confidence and load building to financing major capital developments.

4) The changed plan is not rooted in any material net change in facts since NFAT or the last GRA (IFF14).

a. MIPUG's submission on this matter is contained in **Issue Paper #4** focusing on the changes in financial projections from NFAT to the previous GRA (2105 GRA based on IFF14) to the updated scenarios.

b. MIPUG's submission focuses on how there has be relatively little change in the underlying financial conditions and inputs since NFAT or IFF14, and where these have arisen they are largely offset by other variables (e.g., capital costs and debt are higher, but the carrying costs of this debt in terms of interest rates are lower).

c. At the same time, the risk profile has improved dramatically for the updated scenarios compared to NFAT and IFF14.

5) The purported benefits of Hydro's plan are narrow and overstated.

a. MIPUG's submission on this matter is contained in **Issue Paper #5** on the Purported Benefits of the 7.9% Plan.

b. A key focus of the MIPUG submission is that there has been little tangible evidence of benefits that will arise under Hydro's plan. Multiple witnesses, including Hydro's, testified that access to capital markets is not in doubt.

c. To the extent that downward credit rating pressures did arise, evidence is that this is not a direct impact on Hydro's borrowing costs, and if anything it's the provincial economy that will affect Hydro's debt costs more than its own financial position.

d. Finally, the purported offsetting "benefit" of storing ratepayer funds in Hydro to avoid some measure of interest expense, at low government guaranteed rates, is inferior to other alternative uses of funds available to ratepayers. Note that Hydro is not planning to use these funds for new spending or other economic stimulation – the effect is only to reduce debt, which will be a net drag on the Manitoba economy.

6) The risks and impacts of the plan are unknown but potentially large.

a. MIPUG's summary of this matter is provided in **Issue Paper #6** on the risks and impacts of the plan.

b. The evidence is that Hydro has likely understated the degree of load reduction that may occur under its plan (particularly industrial), and this will undermine revenues and therefore undermine the financial progress targeted.

c. Second, Hydro has led no study on the economic impacts on the province arising from its plan (even though it is the provincial economy that is the most important factor in Hydro's borrowing costs, not Hydro's 'self-supporting' status). The evidence in this hearing is that the impacts could be large.

d. Finally, the Board must be attentive to the "moral hazard" concept noted by Mr. Forrest – that is the temptation that arises for parties to act differently when large equity surpluses are being generated, including Hydro (inefficient growth of O&M costs) or the government (new or increased charges which add costs to ratepayers).

In assessing Hydro's current application, it is clear why comparisons to past GRAs are relevant – those past Board decisions set out a clear indication of the practical application of Hydro's financial target measures, and form the basis of customer plans and expectations. Hydro appears to now dispute, however, whether comparisons to NFAT projections and plans are relevant for rate setting. This is unexpected. Consider the following:

i. The NFAT Terms of Reference specifically required the PUB to consider "(t)he impact on domestic electricity rates over time with and without the Plan and with alternatives" and the "…overall socio-economic benefit to Manitobans…". Without a concept of how rates may be set with the projects, how could the Board ever consider the impact on domestic electricity rates?

ii. The NFAT Report from the Board specifically noted that the multiple rate projections were provided for the Board's consideration, including those that "would moderate the projected rate increases"[8] from the 3.95% otherwise projected. The Board noted that Hydro went out of its way to indicate that these projections "do not indicate a policy change or yielding on its financial targets"[9]. Notwithstanding this objection from Hydro, the Board did conclude that rates should be moderated in such manner, and concluded that "The Panel supports a relaxation of Manitoba Hydro's 75/25 debt-to-equity ratio to smooth out rate increases and the Panel concludes that Manitoba Hydro would still be left with sufficient retained earnings if the equity level was decreased."[10]

Of course no previous IFF nor NFAT projection should be viewed as a guarantee of future rates. Facts and projections can change, and this can lead to changed calculations of rate needs. But it appears there is no basis for dispute that Hydro prepared the NFAT "moderated" rate increase scenario with the express wording that it "more closely aligns with how Manitoba Hydro may smooth these rate adjustments in practice"[11]. Further, there should be no dispute that with respect to rate impacts projected when Hydro was strongly advocating for its large capital build program (including Conawapa), Hydro made clear reference to how it would be patient with the return to 75% debt ratios over up to 2 decades. Could facts drive rates up from the 3.95% level? This point appears to be obvious. But in no way did Hydro communicate, nor should customers have reasonably expected, that the most adverse impact on their future rates, as a result of the capital projects that Hydro advocated, would not be Hydro experiencing overall adverse financial impacts, but instead Hydro altering its core financial principles on how quickly it wanted to build equity in the major new developments. Note in particular that NFAT's forecast was a 75% debt ratio by 2031/32, 11 years after Keeyask was fully in-service, compared to today's desire for 75% debt by 2026/27, which is only 4 years after Keeyask is fully in-service.

In terms of Hydro's claims in support of the new higher rate path, the following Issue Papers have also been prepared:

[8] NFAT Report, page 188
[9] NFAT Report, page 188
[10] NFAT Report, page 29.
[11] NFAT Exhibit 104-12, as quoted at Transcript from this proceeding page 1771.

7) Are rates today sufficient for the plants that are now in service?

a. **Issue Paper #7** summarizes the appropriate tests for rate sufficiency, as well as the tests Hydro is now attempting to use.

b. MIPUG concludes that Hydro's current rates are allowing it to meet financial targets and grow retained earnings, and maintain 25% equity ratio on all existing assets (even despite this equity ratio including an as-yet unrealized assumption of a $1 billion adverse move (i.e., future potential losses) on assumed pension plan returns and USD exchange rates compared to 5 years ago.

c. For 2017/18, all ongoing costs of the utility are financed with internally generated cash, other than major new generation, transmission, and long-lives DSM programs. This includes financing over $500 million of "sustaining" capital with cash, even though these represent in many cases major asset improvements and renewal that will last for decades into the future, and be depreciated over that future useful life as part of ratepayer expenses

d. MIPUG recommends that the Board view with skepticism (if not outright rejection) Hydro's ongoing and inconsistent attempts to redefine long-established financial metrics. If Hydro wishes to now change the financial metrics and targets established decades ago, and thoroughly reviewed and refreshed as recently as within the last 3 years by KPMG, Hydro should bring such proposals to the PUB for a thorough review with proper analysis of the principles and implications of the change.

8) Will Bipole III drive a major rate increase upon coming into service? Also, should the same type of deferral/transition funding be implemented for Keeyask as was used via the Bipole III deferral account?

a. **Issue Paper #8** reviews that Bipole is in fact already in rates to a total of $40 million annually (per Hydro's figures in PUB MFR-20) and the total rate increases required over and above what is already in rates as the Bipole III rider is only 1.4% in each of 2018/19 and 2019/20, and a further approximately 2% in each of 2022/23 and 2023/24.

b. Further, this degree of rate change will lead to Bipole III costs being fully funded from the time it comes into service and the deferral ends – no transition provision is assumed (e.g., absorbing net losses) which is extraordinary considering Bipole is the largest asset Hydro has ever constructed (pending Keeyask) and is non-revenue-generating.

c. While the Bipole III deferral account was an effective measure to help transition Bipole into rates, the same principle does not apply to Keeyask.

Having addressed the above matters, which relate primarily to Hydro's view of the financial forecast, there are a number of specific items in Hydro's financial forecasts that are problematic, in terms of being overly pessimistic. This includes the following:

9) Regulatory deferral accounts

a. Hydro has provided proposals for the amortization of Conawapa costs, the Bipole III deferral account and gains and losses on disposals to which MIPUG takes no issue. Approvals related to regulatory deferral accounts are summarized in **Issue Paper #9**.

b. MIPUG takes the position that Hydro has failed to reflect the words and intent of the Board's previous direction with respect to the deferred overheads account and the issue of depreciation procedure (ASL versus ELG). In each case, Hydro's approach significantly increases the costs projected over the next 10 and 20 year timeframes under MH16 Update with Interim assumptions.

c. The deferred overhead account should continue to operate indefinitely and be amortized over 30 years, consistent with the Board's conclusion in Order 73/15, referencing Attachment 46 as the basis for the 3.36% rate increase awarded at that time.

d. The depreciation issue should be managed in a manner Hydro finds appropriate that leads to only the costs of an ASL depreciation procedure being included in rates in each year, indefinitely. This is consistent with no amortization of any ELG/ASL difference. No such amortization should be required, as the two procedures lead to the same overall cost over time, and as such as self-balancing.

10) Sustaining Capital Investment

a. MIPUG's summary of key considerations with respect to sustaining capital investment is set out at **Issue Paper #10**. That paper highlights that the Board should treat Hydro's sustaining capital projections with caution and skepticism, and should retain pressures on Hydro to pace and prioritize the degree of spending occurring.

b. The latest capital expenditure forecasts continue to retain the high sustaining capital expenditure levels seen at the last GRA (from CEF14) despite those levels being a full $100 million per year higher than the CEF13 levels, and the pressures of the Board for Hydro to engage in pacing and prioritization.

c. BCG similarly highlighted that Hydro could target $100 million/year in reductions tied to "lower value capital projects"[12]. Despite this, no such reductions have been shown.

d. While Hydro repeatedly claims it has no alternatives to spending at the levels identified, MIPUG cross-examination of just one project shows that Hydro reduced the budget for the Gillam Redevelopment from $366 million to $266 million to $225 million and expects further reductions in this level (portions of which are not yet included in the MH16 Update with Interim financial forecast). At each instance for which a Capital Project Justification form was provided, this project repeatedly identified that there were "No other alternatives were considered as the work must be completed"[13], despite clear evidence that there were alternatives each of which involved lower costs than the previous justification form targeted.

11) Pessimistic Forecasts in Various Areas, Including Export Pricing

a. MIPUG highlights a number of areas where Hydro's forecasts have been shown to be pessimistic as compared to best estimates of future conditions. These areas are reviewed in **Issue Paper #11**.

b. The load forecast used for any scenario that applies rate increases lower than 7.9% still includes an elasticity effect (lost load) arising from an assumed 7.9% price response. This is because Hydro did not produce a load forecast consistent with a 20-year style of rate increase (e.g., 3.36% to 3.57%). As a result, all scenarios that have been modelled with a 20 year focus include an inappropriately pessimistic price response assumption in regard to future domestic loads.

[12] PUB-MFR-72 page 133 of 615

[13] See, for example, PUB MFR-115 Attachments page 277.

c. With respect to export prices, Hydro's new policy decision to exclude all future capacity revenues and dependability premiums has been described by Daymark as a "P100" assumption – an effective worst case. This approach should be rejected by the Board if Hydro's basic IFF framework of best-forecast conditions is to be applied on an internally consistent basis.

d. For interest rates, the evidence in this proceeding is that for at least a significant part of 2017, Hydro was borrowing at 30 year rates that were well below forecast. As the scale of borrowings is very large ($10 million per working day in 2017/18) these interest rate benefits will have been locked in on a substantial complement of long-term debt. The Board should be attentive to this fact when reviewing scenarios – i.e., that no scenarios have been updated for known interest rate benefits.

e. On the issue of possible cost overruns for Keeyask, should any cost overrun be confirmed it should similarly be included in Hydro's best estimate forecasts. However, to this time, no such new overrun (of the type hypothesized by MGF) has been confirmed. MIPUG recommends that Hydro complete the 2018 summer construction season and as soon as factual information is available regarding Keeyask productivity that Hydro bring that information back for PUB review as part of any request for 2019 rate increases. At this time, it is premature to conclude that further cost overruns compared to the estimates used in MH16 Update with Interim are sufficiently likely to include in IFF projections.

12) Demand Side Management (DSM) Spending Assumptions

a. Issues associated with Hydro's DSM spending assumptions are set out in **Issue Topic #12**.

b. The DSM levels included in MH16 Update with Interim assume a level of DSM that involves excessive savings targets compared to what Integrated Resources Planning should mandate. This is particularly true given the material decrease (almost 1/3) in generation marginal cost values provided during the course of the hearing.

c. The effect of benchmarking DSM too high is both excessive spending, and excessive load reductions that fall into the range which Dr. Yatchew described as "sub-optimal".

d. The PUB should ensure financial forecasts relied upon today reflect a lower level of DSM than in the recent past, when marginal cost values were much higher. Similarly, this assumption should be based in a rational expectation that Efficiency Manitoba's savings plan will not target 1.5% savings by rote, but rather will involve a recommendation to the Lieutenant-Governor-in-Council that a more appropriate cost-effective level of DSM, consistent with Integrated Resources Planning and with mitigating rate impacts, should be targeted.

In summary, when reviewing forecasts based on MH16, the Board should ensure that it considers whether the forecast retains pessimistic assumptions for regulatory deferral accounts (depreciation and deferred overheads), sustaining capital investment (insufficient pacing and prioritization, plus benefits of capital project reductions that have been undertaken since IFF16 was prepared), load forecasts (excessive assumed price response, if the revenues are not based on the same degree of price increase), export prices (policy decisions to exclude best forecast projections of export revenues), interest rates (failing to include benefits of 2017 30-year debt cost reductions), and DSM expenditures (excessive assumed DSM spending, including effects on both costs and loads).

A final submission on revenue requirements relates to risk and uncertainty.

13) Use of uncertainty analysis as part of future rate-setting improvements

a. A key consideration driving the contested issues in this proceeding is fundamental miscommunication about the sufficiency of rates, and the purpose of reserves, rate increases and financial targets. This topic is addressed in **Issue Paper #13** regarding the uncertainty analysis and future rate-setting evolution.

b. In MIPUG's view, the uncertainty analysis tool shows significant potential for communicating the sufficiency of Hydro's rates, and for making clear to parties such as capital markets regarding how and when the PUB may act in future if true adverse conditions arise such as any situations that threaten debt repayment.

c. The tool can also help convey alternative approaches for the degree to which ratepayers may set aside reserves today to help avoid risks of rate shock in future, in a quantitative and analytical fashion.

d. Advancement of the tool may be best approached as part of a technical forum, including intervenors.

In respect of Cost of Service, Hydro has prepared a Cost of Service study (PCOSS18) which largely addresses all issues outstanding from Order 164/16. The sole remaining issue in MIPUG's view is an over allocation of costs from the category of Customer Service General.

14) **Customer Service General (C10) allocation to the large industrial classes**

a. MIPUG's position on Customer Service is set out at **Issue Paper 14**.

b. The evidence indicates that these costs relate primarily to the distribution system which is not used by the large industrial customer, or relate to services which the industrial customers already receive (and pay for) through their own customer service allocation known as C23. As a result, a significant portion of the C10 costs should not be allocated to the industrial classes (GSL 30-100kV and GSL >100kV).

In respect of rate design, Hydro has proposed across-the-board increases with no change to the industrial customer rate design, ignoring the results of its recently completed cost of service study (PCOSS18).

15) Rate design – overall class revenues and industrial class rate design.

a. The issue of Hydro's Revenue:Cost Coverage (RCC) ratios is reviewed in **Issue Paper #15**, as is the potential to move towards an optional Time of Use pricing arrangement for industrial customers.

b. Proposals for rate increases applied across-the-board should be rejected in favour of a rate design that provides a 1-2% lower than average increase to the classes that are well outside the Zone of Reasonableness of 95-105 (GSL >100 kV, GSL 30-100 kV, as well as GSS – Non-Demand).

c. Hydro should be directed to develop, in consultation with interested customers, an optional Time-Of-Use industrial rate design such that customers who see benefits from this type of rate can opt-in.

ISSUE TOPIC #1:

ISSUE: REGULATORY SIGNALLING AND ASYMMETRY

By selecting a rate increase for 2018/19 rooted in a 10 year plan to re-establish a 75% debt ratio (7.9%), versus a rate increase more reminiscent of the previous 20 year rate plans (e.g., 3.36% or 3.57%), does the Board send a signal to stakeholders, particularly customers and capital markets, that could have unavoidable adverse consequences?

MIPUG SUMMARY AND/OR RECOMMENDATION:

In MIPUG's submission, the Board cannot avoid sending a regulatory signal with this Order. However, the impacts of the signal are asymmetrical. Electing a 7.9% rate path portrays an acceptance of Hydro's basic rationale that debt is too high and debt ratios must be achieved within 10 years, which can only be understood to mean further 7.9% increases are coming. In contrast, retaining a 20 year plan, but with clear language that the Board will act in the case of bona fide threats to Hydro's ability to recover its costs and make good to its lenders, can suffice to provide comfort to credit markets that Hydro's financial condition is being actively managed. Such a signal should not be viewed by credit markets as a regulator acting negligently, but rather acting with consistency and conviction.

DISCUSSION AND SUPPORT:

In regard to the issue of the requested approval, which only includes one more <u>requested</u> rate increase (7.9% as of April 1, 2018) versus Hydro's <u>plan</u> for multi-year 7.9% increases, the Board has been clear that the only application before it is for the 2018/19 rate increase[1]. Despite this, in MIPUG's view, the Board cannot avoid addressing the issue of Hydro's new plan. As put by Mr. Osler:

> MR. CAMERON OSLER: … But you are being asked in this instance to just -- the only justification you're being given for 7.9 versus the type of number your predecessors on this Board heard, the only reason you're being given is because of an asserted target that has been met with a certain time period. Absent that reason, there's no basis for changing the rate framework from what the Board looked at last time it met to review Hydro's material. So the applicant has asked you to de facto consider something beyond the test years to justify what you have -- they're asking you to do in the test years. I -- my suggestion is you probably have to

[1] As well as confirming the two interim rate increases of 3.36% effective as of August 1, 2016 and August 1, 2017

> comment on that. You can't avoid it given the nature of the application. [T6056-6057]

Further, Mr. Forrest noted:

> MR. GERALD FORREST: ... Yes, the application is that you're going to deal with the two (2) interim rate increases and you're going to deal with the rate for next year. But because the application before you has the rate path scenario that you've either got to buy into it or not buy into it, in my opinion. And as pointed out by other witnesses, when I've had a chance to read a bit of the transcript, there's going to be a lot of people out there who are going to read your order in depth. And they will need signals as to which way you are proposing to go.
>
> …
>
> From the public's point of view, and certainly from our client's point of view, this could alter the way they do business in the long-term, this application. So however you deal with it, you need to deal with it with the thought in process. [T6057-6058]

With respect to the specific audiences, Dr. Yatchew provided useful comment on the theory of a regulator's "signal" to power users:

> DR. ADONIS YATCHEW: ... The regulatory decision made in this proceeding, which ostensibly deals with a two (2) year test period, will have an important impact on decision-making on industry -- by industry, because it will signal the likely future path of rate increases. If an increase of close to 7.9 percent is approved, that will suggest acceptance of Manitoba Hydro arguments and its time profile of -- its -- its focus on the time profile of future financial ratios, which is part of the core argument that Manitoba Hydro is advancing. So while we can talk about a 7.9 percent, once you've signaled that, then you're really -- the customer, and certainly the business plans are going to be thinking, this isn't ending. This is going to go on for a while. [T4440]

At page 4495 of the transcript, Mr. Hacault further explored with Dr. Yatchew his comments that "Indeed, the specter of increasing rates in the nearer or more distant future may have already discouraged investment."[2] Dr. Yatchew explained:

[2] Transcript 4495

> DR. ADONIS YATCHEW: ... That's evidence, that's empirical evidence and its quite persuasive that firms will often pick -- part of their decision matrix, as I say here, is picking their locations and their investments, their initial locations and their future plans, and investments based on what they think energy prices are going to be or electricity prices are going to be depending on which kind of energy they're particularly reliant upon. So that's -- let me just add to that that when they construct these business plans, they don't do it on just what prices are today and yesterday, they form expectations about future prices. That's a standard sort of textbook optimization problem in micro theory that this is how sort of -- the bare-bones skeleton modelling of how the kinds of things that businesses need to take into account. [T4496]

In respect of customer comments, a large industrial customer - Chemtrade Logistics, noted that with respect to capital investment, the climate Hydro created by signalling large prospective rate increases into the future is already causing investment to be on hold:

> MR. MICHAEL ST. PIERRE: ... We will spend a certain amount of subsistence capital for sure, as long as the plant operates. And we have publicly announced intentions to invest an additional $50 million into our facility. These [discretionary] investments have plans and timelines to implement.
>
> However, we find it difficult to proceed in light of the numerous and significant electricity cost increases announced by Hydro. We, and our competitors across North America and internationally, are watching what Manitoba will do. The signal PUB will send to industry regarding current rates, as well as future projected rate increases, will clearly signal the province's desire to compete with other jurisdictions and attract competitive and additional investments. The world is watching. [T7720-7721]
>
> …
>
> And I know you've been very clear about looking only at one (1) year, unfortunately, our capital is looking out ten (10), twenty (20) years. [T7763]

Chemtrade further noted that it is not only a question of investment and impacts on Chemtrade’s cost structure, the fact is the chlorate market prices and contracting is also already seeing spin off effects, even pending the Board's first decision on Hydro's new more aggressive rate increases:

> MR. MICHAEL ST. PIERRE: ... So what we see as a competitor is because everyone is looking at Manitoba, our customers look at us different because they're wondering what's going to happen. Our competitors are acting a bit different. And some of our competitor costs -- we don't actually know, because they're private contracts, but we're looking at the activity, and I won't say I'm scared. I'm concerned, right? So we see that, and people are watching. [T7764]

The Mining Association of Manitoba delivered similar perspectives:

> MS. ANDREA MCLANDRESS: … So the key here, the point is that large energy cost increases, as well as the signal that those increases will continue over time, have major, material, detrimental effect on project valuations upon which investment decisions are based. [T7666-7667]

To summarize, one fundamental conclusion for this hearing is that customers have been put into a highly uncertain position with the actions taken by Hydro. It is imperative that the Board recognize there is no way to adjudicate on the current application for 2018/19 rates without, in effect, either explicitly, or inadvertently implicitly, communicating whether the Board supports Hydro's plan. In short, the Board's Order will be a signal to customers regarding which rate paths are likely to unfold in the future.

At the same time, at all times leading up to this hearing, Hydro has indicated credit ratings agencies and lenders can appreciate the nuance of financial target erosion in light of long-planned capital investment, specifically stated under cross-examination of Hydro's treasurer Manfred Schulz at the NFAT proceeding when 20 year targets were used to re-establish 75% debt ratios:[3]

> MR. BOB PETERS: All right. Let's turn, please, to page 204, also under Tab 23 at Exhibit 58-4. It's just the next page. And if we go down to the challenges, we see at the bottom of the page there's three (3) challenges listed, Mr. Schulz. And we've talked a fair bit about hydrology risk; and this is just recognition by DBRS that Manitoba Hydro faces exposure because of its hydrology risk, correct?

> MR. MANFRED SCHULZ: Correct.

[3] NFAT transcript Page 3073, line 25 to Page 3077, line 2; reproduced in Attachment C to Bowman pre-filed testimony in the current proceeding (MIPUG Exhibit 13).

MR. BOB PETERS: And when we get down to the high leverage, Manitoba Hydro's leverage remains one (1) of the highest among government-owned integrated utilities in Canada, limiting its financial flexibility going forward. I read that correctly?

MR. MANFRED SCHULZ: You read that correctly. And that reinforces the point about why the equity ratio is important for us and why -- and through the eyes of the credit rating agencies, the continued vigilance on the debt-equity ratio and our equity ratio and our financials is so important for them, because this is something that has a fair amount of visibility. And coming to the point about the regulatory support, if we had a situation where we were not getting the regulatory support in order for us to continue with that, they would consider that to be a weakness for us. But thus far, the regulatory regime has been supportive of our requirements.

MR. BOB PETERS: But we know that the debt-equity ratio is going to suffer over the next -- it's going to be below target at least over the next twenty-two (22) years, according to forecast, Mr. Schulz, correct?

MR. MANFRED SCHULZ: Correct. And they're aware of that.

MR. BOB PETERS: And when they say Manitoba Hydro will have reduced financial flexibility, what does Manitoba Hydro understand that to mean?

MR. MANFRED SCHULZ: When you take on more leverage, you take on more debt. You have less ability to take on further debt, which means you know, you reach limits in saturation. So it's nothing more specific to that than that. And so the more leverage you have the -- it's just a natural consequence, the more debt that you have, the less flexibility you have.

MR. BOB PETERS: And so the additional increased costs of Keeyask and Conawapa that were announced March the 10th result in decreased financial flexibility for the Corporation?

MR. MANFRED SCHULZ: Not necessarily. I mean, there's a lot of other puts and takes to this. So, again, we're looking at this from a corporate perspective. It wouldn't move the needle, from their perspective. And keeping in mind that the credit rating agencies, and DBRS in particular, when they're looking at this, have looked at all of our financial ratios. They've looked at all of the forecasts. They're fairly close observers of the

> regulatory proceedings. So we actually find them to be, as the other credit ratings used to be, fairly informed in terms of the matters for not only Manitoba Hydro, but also as part of their utility analysts, all the other utilities, oil, BC Hydro you know, they're analysts; they do this as a full time job, looking at the regulatory practices. So this is a common occurrence for there to be increased capital expenditures. They're aware of it. They see the equity ratios. They see the -- you know, the investment periods. It's a natural consequence that they see the returns. And we -- they see there's been a planned outcome, and so they're not too alarmed or startled by it all. In fact, they see this as generally something that seems to be positive in the general context of what the need is for moving forward.

There appears to be no basis for disagreement that some degree of signalling duty is owed to capital markets (and similar parties) to convey the existing strength in Hydro, and the resolve of the system to ensure Hydro maintains a full cost recovery operation, with sufficient (but not excessive) reserves. For example, note the following exchange with Mr. Coloaiacovo:

> MR. CHRISTIAN MONNIN: … In your report you state that Manitoba Hydro is self-supporting as long as it has cash flows -- as long as its cash flows continue to be sufficient to cover its costs including the debt costs.
>
> MR. PELINO COLAIACOVO: That comes directly from the first page at the top of D[B]RS's report. It's an -- almost a quote.
>
> MR. CHRISTIAN MONNIN: And do you adopt that?
>
> MR. PELINO COLAIACOVO: Yes.
>
> MR. CHRISTIAN MONNIN: And so in your opinion, is it safe to say Manitoba Hydro does not need the proposed rate increases or the time frame to attain this?
>
> MR. PELINO COLAIACOVO: I believe that's true. I don't think that there is sufficient support to justify the application that they've made.
>
> MR. CHRISTIAN MONNIN: In your evidence, Mr. Colaiacovo, was that this Board, the Public Utilities Board, should provide some clarity and signal to capital markets but whether Manitoba Hydro is self-supporting?

> MR. PELINO COLAIACOVO: I think the capital markets do believe that Manitoba Hydro is self-supporting. I think Manitoba Hydro itself has thrown some confusion by the statements that they've made in their application, suggesting that they're facing unacceptable risk.
>
> It would be helpful and beneficial if the risk issues were clarified and if the long-term rate path was clarified somewhat to provide reassurance to capital markets that, in fact, the rate -- the Board at least is not concerned about Manitoba Hydro's self-supporting status.
>
> MR. CHRISTIAN MONNIN: And how would the Board go about doing this, Mr. Colaiacovo?
>
> MR. PELINO COLAIACOVO: I think by enunciating a policy on how rates are going to be managed and reassuring markets that rates will be managed in a fashion to ensure that Manitoba Hydro continues to pay its bills, as it has in the past. And I think that will be a reassuring message. [T4982-4984]

Similarly, Mr. Osler noted:

> MR. CAMERON OSLER: Our recommendations, in summary, to the Board for review of this application. Number 1, retained the Board's long-established rate principles, avoid hard dates to achieve 15 or 25 percent equity ratios. And I would say, from the previous slide, have regular initial re -- you know, reviews and a process of regular change. Let the markets know that you will adjust if you have to, rather than adjust in advance for what might happen. [T6052]

Even Hydro's current witnesses note that the core issue for capital markets is confidence that the Board will manage problems and adapt as circumstances dictate:

> MR. JAMES MCCALLUM: Well, I think, and I think I've given this testimony already that the primary goal should be to manage the debt of the Corporation to a level that keeps the risk of the Corporation to its ratepayers in the form of higher and more volatile rates to an appropriate level. Now, "appropriate" is obviously a word that means a lot to a lot -- a different thing to a lot of people.
>
> The collateral benefit of doing that, it is vitally important to maintain the confidence of investors and whether you -- let's call it the capital markets, in general, which includes all participants inclusive of rating agencies and they really are, you know, in a sense synonymous. Investors -- you know,

> confidence is a funny thing. It's an intangible, but they, in my experience anyway, investors very much want to feel like you are managing a problem and that they have confidence that you are managing a problem and that you are going to continue to manage the problem aggressively as your circumstances change and different prescription is required.
>
> DR. BYRON WILLIAMS: And when the markets, sir, look to regulated industries, they will be looking to the actions both of the industry and of its regulator; agreed?
>
> MR. JAMES MCCALLUM: I agree with that, yes. [T1521-1522]

MIPUG is well aware that the Board cannot, and will not, fetter its own discretion to deal with future rate increases based on the evidence available at that time. However, 'not fetter' effectively runs in opposition to the inevitable 'regulatory signalling'. With respect to future discretion, one key question at this time is whether the Board can:

a) adopt a one-time 10 year focused increase (e.g., 7.9%) yet still convey that it has not doomed ratepayers to many years of similar pressures, or, conversely

b) retain a 20 year focused increase (e.g., 3.36% to 3.57%) and still find a way to broadcast to capital markets that the Board is committed to Hydro recovering all its costs, and is not being irresponsible or unconcerned with lenders being repaid.

A major problem for today is that the two above scenarios reflect asymmetrical signalling. Looking only to the difference between two broad general rate levels, loosely characterized by 10 year plans (7.9%) versus 20 year (e.g., range of 3.36% to 3.57%), the following are noted:

- If the Board approves 7.9%, it cannot help but convey that it has bought into Hydro's case that Hydro's debt levels are too high. Having bought into this logic, there is simply no way a rational customer can conclude that the Board will do anything other than award further 7.9% increases for the foreseeable future, since there is no way Hydro will see even a dent in its maximum debt until, at best, such time as rates have been driven to much higher levels many years into the future. If this fact of projected high peak debt is a good enough rationale for 7.9% today, it should be understood that the fate has been sealed for 7.9% increases for the foreseeable future. Customer confidence will be inevitably shaken by today's Board decision, notwithstanding any assurances to the contrary the Board may provide.
- On the contrary, the evidence is capital markets and credit rating agencies derive their confidence from multiple sources: e.g., the provincial backstop (and the

> strength of the underlying provincial economy), the competitiveness of Hydro's rates, the confidence in the regulatory regime. More importantly, the above testimony notes that these capital market participants rely on clear signals that future rate increases could be undertaken <u>upon serious erosion that threatens Hydro's ability to repay</u>. By adopting a plan rooted in a continued focus on 20 year achievement of targets (e.g., the range of 3.36% to 3.57% increases) the Board still has many ways to convey with its directives and reasonings that it (a) is fully prepared to act to ensure Hydro remains fully self-supporting, to the benefit of capital market investors, (b) does not see the current forecasts as threatening Hydro's ability to repay lenders, and (c) will remain diligent and attentive to testing Hydro's reserve levels at least annually, and will act if facts evolve to be more adverse than currently anticipated.

If there is an issue with respect to capital markets today, as compared to projections that markets were purportedly able to understand and support as recently as the Needs For and Alternatives To review, it appears it is first and foremost rooted in communication (and more precisely, miscommunication). For example, there appears to be a fundamental misunderstanding with respect to Hydro's financial targets, as noted by Mr. Osler when he indicated the 25 percent equity ratio should be understood not as a hard target to be rapidly re-achieved:

> MR. CAMERON OSLER: ... So, what I take away from that is, yes, you -- the Board has encouraged the Utility, and the Board of Directors of the Utility has encouraged everybody, to have these targets and I don't dispute their value in terms of trying to be clear to everybody.
>
> But, when we say 25 percent equity ratio, we happened to have been there five (5) years out of the last umpteen decades. Does that mean to an ordinary person that we have to get back there right away? Obviously it meant that to somebody who came into this job, you know, and tried to deal with -- I will assume responsibly with their obligations. And they were shocked.
>
> But from a regulatory point of view that target -- I never interpreted it to mean that type of thing. So there's a communication problem here. That target is there to give a valid basis for building up reserves to that level without reducing rates. And I fully support it for that reason, as long as the rates that we're talking about that are being used to build it up are less than inflation and certainly not more than inflation. [T6425-6426]

Further, as noted by Mr. Bowman, the communication from Hydro focuses on the numerical measurement of a 75:25 debt:equity target (or 1.2 capital coverage target) on a pass/fail type metric, while ignoring the critical language that surrounds the target:

> MR. PATRICK BOWMAN: I think the idea -- the other word that needs a focus here, is we've talked about target. And people get very caught up on what the number in a target is, 75 percent or one-point-two (1.2). The target, though, always has the words around it that say, Things will proceed towards, consistent with rate stability, and a bunch of other words, that everyone wants to ignore the words and just focus on the number. So be a bit careful about that. [T6411-6412]

Other relevant language is also set out in Hydro's own Financial Targets Review at Appendix 4.2 to the GRA filing[4]:

> In setting financial targets, it was recognized that the targets may not be attained during years of major investments in the generation and transmission system, but that it would be necessary for Manitoba Hydro to demonstrate to credit rating agencies and other stakeholders, that progress towards attaining the targets would occur over the long-term after the major capital system expansion program.[5]

There is also a communication problem caused by sensational claims. For example, the interim rate increase submission from the Coalition noted that on February 7, 2017 the Chair of Manitoba Hydro stated "We want to make people understand, this is a big problem. It's not a small problem. We take that position not only from Manitoba Hydro's perspective, but from the perspective of the government of Manitoba and the people of Manitoba; Hydro is a ticking time bomb"[6]. This followed well known and highly publicized comments from Hydro's own Minister that the Corporation had been made "bankrupt"[7]. Such claims appear to be of no useful contribution towards the confidence of capital markets.

In short, regulatory signalling should be a key consideration for the Board regarding the public interest. In the absence of extremely strong evidence of threats to Hydro's ability to repay its lenders, the precautionary principle suggests a strong rationale for prioritizing the needs of customers for confidence and rate predictability. This can be achieved by maintaining the status quo, 20 year type of approach to rates, combined with a clear message to capital markets that the Board is prepared to further act when truly needed, rather than for what might happen.

[4] Reviewed with Mr. Markowsky in Board Counsel cross-examination at Transcript 6564

[5] Appendix 4.2, page 1

[6] Per http://www.cbc.ca/news/canada/manitoba/manitoba-hydro-sandy-riley-rate-increases-1.3970470 as cited in Bowman pre-filed testimony(MIPUG Exhibit 13, page 4-3)

[7] https://www.gov.mb.ca/legislature/hansard/41st_1st/hansardpdf/56.pdf, page 2689.

ISSUE TOPIC #2:

ISSUE: UNPRECEDENTED FINANCIAL FRAMEWORK ACHIEVED UNDER A 7.9% RATE PROJECTION

To what extent does the financial performance under a 7.9%/year rate increase plan follow the principles and practice for how Hydro is financed and the role and function of financial targets and reserves?

MIPUG SUMMARY AND/OR RECOMMENDATION:

MIPUG concludes that the financial performance under a 7.9%/year rate increase plan leads to unprecedented and excessive financial achievements, inconsistent with the financial framework established for Hydro since it began being regulated in the late 1980s. The current rate increase plan is not just different from past projections by a matter of degrees, it is a fundamental step change in the concept of Hydro as a cost recovery utility.

The extraordinary nature of Hydro's 7.9% rate projections is illustrated by the fact that the financial performance cannot even be placed into a long-term context, as the excessive results that are achieved as early as 5 years after Keeyask comes into service (2027/28) leads to a set of forecasts regarding rates, reflecting choices that each have to be disavowed by Hydro to avoid the appearance of nonsense outcomes. (i.e., Do you lower rates 23% to prevent reserves from becoming excessive? Do you let your equity spin upwards out of control even with a decade of no rate increases?, etc.)

DISCUSSION AND SUPPORT:

By adopting a framework that sets out 6 years of 7.9% annual increases (2018/19 to 2023/24) followed by 4.54% (2024/25) and 2% per year thereafter, Hydro achieves a financial performance that is fundamentally different than under all previous history since regulation began in Manitoba in the late 1980s.

Evidence in support of this conclusion is as follows[1]:

1) The projection for net income is that Hydro would achieve record net income levels by 2021/22, the year before Keeyask comes fully into service[2], and remain above the previous record net income level for effectively every year into the future.

[1] Per Appendix 3.8

[2] Compared to previous record net income of $415 million in 2006.

2) Hydro would achieve a retained earnings of $6.564 billion by 2026/27, compared to the previous record of $2.749 billion.

   a. This record retained earnings (reserves) would be achieved notwithstanding Hydro's 5 year drought has dropped from $2.8 billion in the 2007 Integrated Financial Forecast (IFF) to $1.2 billion in the latest IFF16[3].

More notably, Hydro's current forecasts indicate that even if the most severe 5 year drought on record were to occur during the critical period starting 2019/20 (when Keeyask was still under construction and finances are at their weakest), Hydro's rate path would lead to a positive net income over the 5 years of drought of $528 million[4]. This is inconsistent with Hydro's normal concept for financing droughts, which were to maintain reserves to address net losses driven by low water (e.g., the 2003/04 drought which led to a $436 million one year net loss).

Exhibit PUB/MH II-40 (Figure 1 and 2 from this response reproduced below) was reviewed with Mr. Colaiacovo under cross-examination by Mr. Peters, as follows:

> MR. BOB PETERS: So that means, Mr. Colaiacovo, that even though in that scenario, Manitoba Hydro's drought isn't reducing the retained earnings of the Corporation, but it's not allowing it to accumulate as much as it otherwise would have?
>
> MR. PELINO COLAIACOVO: Right. And so I think that begs a bit of a question, because if the point of having reserves is to withstand a drought, why are you actually -- why are your rates so high that during a drought, you're still building your reserves? It's a bit problematic …
> In the 7.9 percent rate path, not only do you have enough reserves, but you're actually still building reserves during a drought. So it raises some questions about whether that 7.9 percent rate increase is actually required. [T5162-5164]

[3] The latest MH16 Update with Interim likely has a lower drought risk than IFF16 as export prices were reduced as part of preparing MH16 Update with Interim.
[4] Per PUB/MH-I-48b, retained earnings moves from $3.053 billion at year-end 2018/19 to $3.581 billion by 2023/24. PUB/MH-II-40 provides a summary with retained earnings levels.

Figure 1

Cumulative Impact to MH16 Update with Interim and 3.95% Retained Earnings

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Base Scenario: Total Retained Earnings										
MH16 Update with Interim and 3.95%	3 056	3 181	3 375	3 368	3 210	3 106	2 955	2 879	2 877	2 992
Sensitivities: Total Retained Earnings										
5 Year Drought (starting in 2019/20)	2 708	2 424	2 446	2 195	1 825					
7 Year Drought (starting in 2019/20)	2 902	2 937	2 964	2 653	1 849	1 422	1 115			
5 Year Drought (starting in 2022/23)				3 093	2 529	2 213	1 774	1 444		
7 Year Drought (starting in 2022/23)				3 227	2 959	2 649	2 134	1 372	959	888
Sensitivities: Incremental Increase/(Decrease) in Retained Earnings										
5 Year Drought (starting in 2019/20)	(348)	(757)	(929)	(1 173)	(1 386)					
7 Year Drought (starting in 2019/20)	(154)	(244)	(411)	(716)	(1 361)	(1 684)	(1 840)			
5 Year Drought (starting in 2022/23)				(275)	(682)	(893)	(1 181)	(1 435)		
7 Year Drought (starting in 2022/23)				(141)	(251)	(457)	(821)	(1 507)	(1 918)	(2 105)

Figure 2

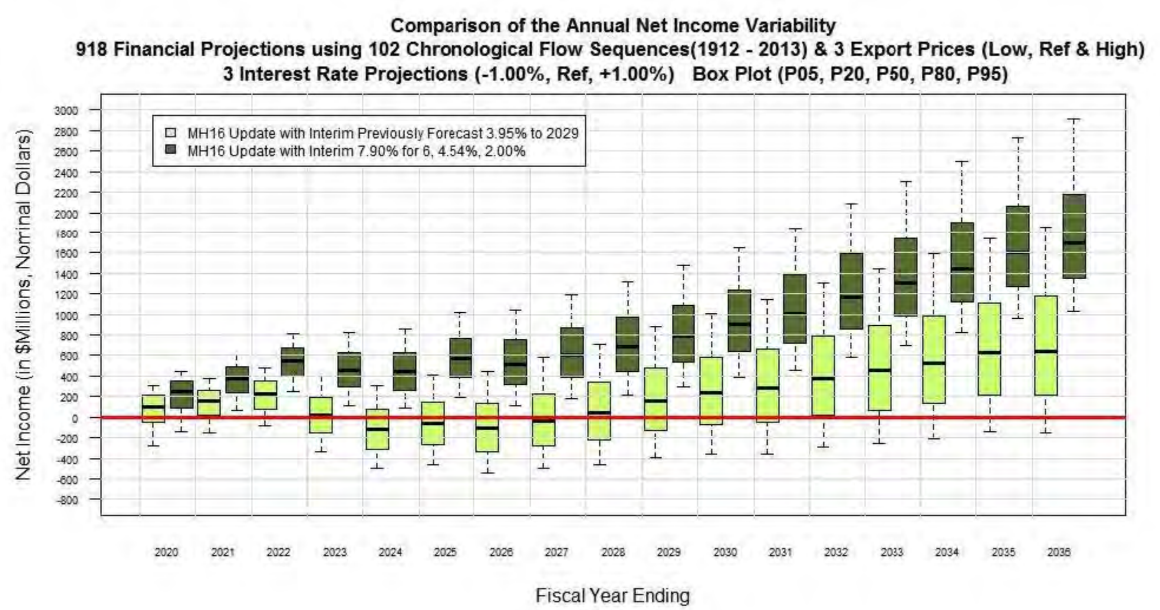
Cumulative Impact to MH16 Update with Interim and 7.90% for 6, 4.54%, 2.00% Retained Earnings

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Base Scenario: Total Retained Earnings										
MH16 Update with Interim 7.90% for 6, 4.54%, 2.00%	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564	7 214	7 969
Sensitivities: Total Retained Earnings										
5 Year Drought (starting in 2019/20)	2 909	2 849	3 195	3 382	3 581					
7 Year Drought (starting in 2019/20)	3 104	3 362	3 713	3 842	3 611	3 826	4 170			
5 Year Drought (starting in 2022/23)				4 283	4 289	4 616	4 828	5 157		
7 Year Drought (starting in 2022/23)				4 416	4 717	5 044	5 177	5 072	5 322	5 911
Sensitivities: Incremental Increase/(Decrease) in Retained Earnings										
5 Year Drought (starting in 2019/20)	(349)	(758)	(929)	(1 175)	(1 388)					
7 Year Drought (starting in 2019/20)	(154)	(244)	(411)	(716)	(1 358)	(1 672)	(1 817)			
5 Year Drought (starting in 2022/23)				(274)	(680)	(882)	(1 159)	(1 407)		
7 Year Drought (starting in 2022/23)				(142)	(252)	(455)	(810)	(1 492)	(1 892)	(2 059)

The updated uncertainty analysis at PUB/MH-II-41a-b[5] further highlights this unprecedented risk profile under Hydro's proposals. This evidence specifically notes that under Hydro's proposed rate increases, even under the combined adverse conditions of high interest rates, low water and adverse export prices, the P05 (5th percentile) net income would remain above $84 million/year in all future years after 2019/20. The box plot graph from this response is reproduced below with Hydro's proposed rate increases shown in dark green (note the 5th percentile line does not cross zero net income in any year after 2020).

[5] PUB/MH-II-41a-b, Pages 7 & 8

Figure 4.18 Comparison of Net Income Variability - MH16 Update with Interim



Further evidence of Hydro's proposed fundamental change to the financial model is Hydro's inability to articulate a consistent credible scenario for what occurs after year 10. Three different concepts have been provided by Hydro, and for each Hydro remained non-committal and distanced itself from the implications of the scenario:

1) Projections based on **continuing modest (2%) rate increases** based on scenarios developed and provided by Hydro as Appendix 3.8. Despite the scenario dropping back to inflationary level increases annually starting 2025/26 (before even the 25% equity ratio has been reached), the equity ratio grows to 64% (debt at 36%) by 2036/37. However, Hydro's CFO noted "(w)e do not have a goal to build 64 percent equity structure."[6]

2) Scenarios based on **significant rate decreases**, such as PUB/MH-II-21a-b pages 6-11 (rate decreases of 19.75%, 3.12%, and 1.11% in 2027/28, 2028/29, 2029/30 respectively). Note that this scenario is described as "Manitoba Hydro's Proposed Rate Path" in the MH Rebuttal Evidence[7], was included in the "Top 10 IRs" document Hydro distributed on the first day of the hearing (MH-65) and was highlighted by both Hydro's President in the Direct Examination under the heading "Why Are We Doing This?" (MH-64, page 30) and Hydro's Chair in his

[6] Transcript, page 277
[7] MH Exhibit 52, Appendix 1.7, page 1 of 2

presentation to the Chamber of Commerce the week before the hearing started (MH-67, page 17). Despite this desire to emphasize this rate decrease scenario in its communications, Hydro was clear that the Corporation would not advocate for it under any circumstances, particularly indicating: "…Manitoba Hydro does not regard as prudent any financial plan that forecasts minimal or negative net income (as the scenario in part b) contemplates)…"[8]. Under cross examination from Mr. Hacault, Hydro took no ownership of advocating the scenario, indicating it only prepared the scenario as it was directed by the PUB[9].

3) Scenarios based on **9 years of no rate changes** after reaching a 75% debt ratio. This scenario, shown in PUB/MH-II-21a-b Alternative 2, still shows unprecedented financial performance, including achieving a 51% equity ratio by the end of the scenario. Hydro confirms this is excessive performance noting: "Income levels and equity ratio growth in the second decade of the IFF are beyond what Manitoba Hydro would regard as needed absent an expectation of significant capital needs in the years beyond the 20 year horizon."[10]

In short, Hydro's proposals provide no credible concept of how the long-term exceptional rate levels sought could fit into a rational utility rate framework in either then near-term (excessive drought protection) or long-term (excessive revenues).

Note that all of the above analysis was conducted using Hydro's MH16 Update with Interim forecasts, unadjusted for issues such as the approach to forecasting export prices, or the excessive assumed DSM under the latest marginal cost projections.

[8] PUB/MH-II-21b, page 3

[9] MR. ANTOINE HACAULT: You see, sir, what I'm -- maybe you can help me understand why the corporation would put a scenario that shows nine (9) consecutive losses as even being a potential scenario, given the aversion of this Corporation in its current plan to any deficits at all.
MR. JAMES MCCALLUM: The scenario was requested by the Public Utilities Board and we responded to it. (Transcript page 1690, lines 13-21).

[10] PUB/MH-II-21a-b, page 5.

ISSUE TOPIC #3:

ISSUE: SENIOR MANAGEMENT EXPERTISE AND EXPERIENCE

To what extent does the new 7.9%/year rate plan to establish a 75% debt ratio within 10 years (and only 4 years after Keeyask fully comes into service) reflect the expertise and experience of Hydro's new management in capital markets and private equity, at the expense of expertise in Crown Corporations, regulated electric utilities, and managing the financial aspects of businesses with very long-lived capital-intensive assets?

MIPUG SUMMARY AND/OR RECOMMENDATION:

The foundations of Hydro's new plan are rooted in a significant turnover of expertise at Hydro, including a near total loss of senior experience in the areas of Crown Corporations, regulated electric utilities, and financial aspects of capital-intensive businesses. As a result, Hydro's plan focuses excessively (and inappropriately) on capital market considerations at the expense of most other relevant stakeholder considerations. While there are benefits from Hydro's newly gained expertise in operations (Kelvin Shepherd) and private equity (Sandy Riley, Jamie McCallum) in terms of finally pursuing needed operating efficiency improvements, the rate plan and the equity injection concept are fundamentally misguided.

DISCUSSION AND SUPPORT:

Since the most recent set of hearings before the Board, each focused on rate setting with an eye to achieving debt-to-equity targets over periods of 20 years (the 2012 GRA, the NFAT review, and the 2015 GRA), Hydro has seen a fundamental change in the senior personnel associated with financial functions.

Notably, the following individuals with long-term experience in capital-intensive utilities, Crown Corporations and regulatory settings were no longer available to Hydro in the preparation of the new financial plan[1]:

- **Vince Warden (2012 GRA), Senior Vice President of Finance:** Mr. Warden was a CMA and held a Fellowship. He held 45 years of experience (his entire career) at Manitoba Hydro, including both pre- and post-regulation.
- **Scott Thomson (2012 GRA, NFAT, 2015 GRA), President and CEO of Hydro:** Mr. Thomson was a CA who led Manitoba Hydro starting 2009, and had held

[1] MIPUG/MH-I-17 Attachments.

senior roles in regulated utilities (though not Crown Corporations) since 1999 (in management consulting and accounting 1986-1999).

- **Darren Rainkie (2012 GRA, NFAT, 2015 GRA), Controller, later Vice President of Finance and CFO:** Mr. Rainkie was a CA and CBV with over 20 years of direct experience in regulated utilities, primarily Crown-owned.
- **Manny Schulz (2012 GRA, NFAT, 2015 GRA), Corporate Controller, then Treasurer:** Mr. Schulz was a CMA and held a Fellowship, as well as an MBA. He had 10 years of experience at Hydro in the roles of controller and treasurer, with previous finance roles prior outside of Crowns and regulated industries.

Loss of experience is a normal evolution for organizations, but the extreme turnover at senior finance roles in this situation is notable. This is particularly true given the significant change in direction proposed, and the extent of new commentary that "Manitoba Hydro's previous financial plan was inadequate and risky, and has failed."[2]

Equally notable, Hydro did not replace or gain access to financial expertise in areas related to Crown Corporations, capital intensive industries, or regulated rate-setting in the new resources that became available to it. The evidence in this proceeding is that Chief Executive leadership was secured from the engineering and operations areas of expertise (Kelvin Shepherd, President and CEO since 2015[3]). Further, evidence is that the plans as presented in this GRA were developed under the close leadership of the Board of Directors, as noted by Mr. Shepherd:

> MR. KELVIN SHEPHERD: … We had to develop a new plan. Working together with the Manitoba Hydro Electric Board, we developed a ten (10) year plan to restore Manitoba Hydro's financial sustainability and achieve key financial goals and metrics. [T162]

Under cross-examination from Board Counsel, Mr. Shepherd further acknowledged:

> MR. BOB PETERS: … And what I'm suggesting is that the one (1) reason that results in this GRA being outside the past rate trajectory would be the tolerance that Manitoba Hydro's board has shown for the risks that has -- that are before the Corporation?

> MR. KELVIN SHEPHERD: No, I don't think I would agree with that characterization.

[2] Transcript page 26, lines 2-3.
[3] Per MH-59

> MR. BOB PETERS: All right, let's -- what I'm looking at on page 47 was that the Manitoba Hydro Board's tolerance for risk has changed considerably and the path back to 25 percent equity of no longer than ten (10) years is in the view of Hydro too risky. We discussed yesterday, Mr. Shepherd, that's the view of the Manitoba Hydro Electric Board of Directors?
>
> MR. KELVIN SHEPHERD: Yes.
>
> MR. BOB PETERS: And it's as a result of that view that the rate increases have doubled from the 3.95 to the 7.90?
>
> MR. KELVIN SHEPHERD: Not solely. I believe that the other factors here are important factors and they would require an adjustment of rate trajectory regardless of the first factor. I do agree the current board's view and evaluation of risk is different and that is a significant factor, but it's not the only factor.
>
> MR. BOB PETERS: Is it the largest of the five (5) factors? Are you able to go that far with me?
>
> MR. KELVIN SHEPHERD: I would say it's a very significant factor because as you would understand time frame is a pretty significant determination when you look at a rate trajectory. [T333-334]

With respect to the finance specific skill set, when it came time to replace the expertise Hydro lost in regulated utility capital-intensive industries, and Crown Corporation finance, the decision was made to instead pursue expertise in Private Equity, Mergers and Acquisitions, and Capital Markets, as set out by Mr. Shepherd:

> MR. KELVIN SHEPHERD: My colleague Jamie McCallum is our Chief Finance and Strategy Officer, a position I appointed him to in early 201[7]. Jamie is new to Manitoba Hydro and to the utilities industry. I brought Jamie to the company in 2016 to work with me in the development and execution of a new strategic and financial direction for the company. We'll talk about this more shortly. But I saw a need for new financial leadership to drive the capital and operating discipline and strategic focus we need to set and meet our goals.
>
> Jamie brings a wealth of experience as a private equity investor and corporate director setting strategic direction in leading capital and financial planning. Jamie spent almost the first decade of his career as an investment banker mostly at two (2) of the largest such firms in the world,

> advising corporate and government clients around the world, around the globe, on capital raising mergers and acquisitions and strategy. He has an expert level of understanding of how companies make business choices, plan and manage their finances, access capital markets, and think about risk. [T131-132]

Under cross-examination by Mr. Hacault, it was noted also that Mr. McCallum's background in the past decade overlaps the financial services roles of Hydro's Board Chair (via Richardson Capital Limited and Richardson Financial Group) in the fields of private equity[4].

In short, the distinct change in direction, driven by the new Board of Directors and the new Management outlook, parallels the extensive loss of senior experience relevant to Manitoba Hydro's situation:

- As a **Crown Corporation**, Hydro operates as a cost-recovery entity with the backing of the provincial debt guarantee. Hydro also operates as a major force in the economy of Manitoba, not just as a single actor in a marketplace. In short, Hydro affects the economy in which it operates, it does not just profit from it. Finally, Hydro cannot raise capital from private investors, so all balancing of capital needs must be done through debt markets. Hydro cannot be bought or sold, "flipped" for profit, or driven out by competitors, as would be typical of firms that operate in the private equity space.
- As a **regulated electric utility**, Hydro operates with a monopoly over its service area. Customers are captive to Hydro's services. Further, Hydro provides an essential service that cannot practically be avoided even over the long-term by most customers.
- As a **regulated capital intensive business** with extensive extremely long-lived assets, Hydro creates value for customers through stability and patience in capital recovery. Pricing is about balancing fairness for current users of assets versus future users (as well as among current users), not focusing on "reverse engineering" what the customer can (in Hydro's view) afford[5].

In short, Hydro's excessive new focus on capital markets, debt ratings agencies, and quickened recovery of investment appears a textbook cognitive bias of Maslow's hammer: that is, that if the tool you know is a hammer, every problem appears to be a nail. That is, when Hydro's books do not convey financial ratios that capital markets

[4] Transcript pages 432 - 433

[5] Note cross-examination of Chemtrade Logistics Group Vice-President of Sulphur Products and Performance Chemicals, Mr. Michael St. Pierre by Hydro counsel, page 7748-7749 of the Transcript.

would likely enjoy from private equity investments, then one must move with haste to sate the capital markets.

Perhaps no issue better illustrates the misguided focus of Hydro's new Senior Management and inexperience with the regulated Crown utility sector than the concept of the "equity injection". To the extent Hydro has an issue going forward with finances, it is an issue of annual costs and rate pressures arising from major new capital assets - it is not an issue of insufficient reserves (or "equity") to deal with risks such as drought (as described by Messrs Osler and Forrest[6], or Mr. Colaiacovo[7]). Further, the most notable aspect of the government's adverse impact on Hydro's finances is the degree of government charges, particularly on new capital. The option of government support has been explored in the past, such as the NFAT report, and options for targeted relief highlighted reductions in government charges for specific rate-related purposes[8]. The Crown utility sector in Canada also has extensive experience with lower and/or relieved government charges as part of developing major new capital, such as the much lower government charges that prevailed when Limestone was brought into service, or the recent BC Government's decision to relieve the Site C project of 2.6 cents/kW.h in government charges[9]. Despite this, the evidence is that Hydro's new Board approached the government not with a request for relief from new charges, but instead with a request for an injection of equity. While no details were provided in respect of that request[10], the outcomes would be nonsensical in terms of support for Hydro:

- In terms of annual cost relief, the only savings that would arise from an equity injection would be from avoided interest (for Hydro). However, given the low rates at which Hydro is now borrowing, each $1 billion in government equity (a large amount in relation to the current Government of Manitoba deficit) would lead to interest savings of only $30 million/year[11]. At the same time, an unknown new cost to ratepayers would presumably arise at some point, as indicated by the Business Council of Manitoba (BCM) who advocated this approach, of "restoring Hydro to a dividend generating asset"[12] which dividend would be a net outflow from rates (and ignoring the erroneous BCM citation of history that Hydro

[6] For example, Transcript 6024-6025
[7] Exhibit CC-45, slides 29 and 30
[8] For example, the NFAT report noted the option of targeting a portion of government charges towards vulnerable customers in northern and aboriginal communities, at page 29.
[9] PUB/MIPUG-16, and MIPUG Exhibit 30.
[10] MH-87
[11] Based on 3% interest for 30 year debt, per MH-68
[12] Transcript June 12, page 180

had at some point in the past been a "dividend generating asset" – as noted by Hydro, no dividends are paid[13]).

- In terms of the net impact from the "equity injection", there are two possible scenarios. These derive from the fact that the Province does not have $1 billion in cash to inject into Hydro, and so must borrow any such injection. First is the scenario related to S&P, which consolidates the books of Hydro and the province for the purposes of their rating calculations. For this type of review, the equity injection would serve no purposes whatsoever, as the same consolidated debt would appear pre- and post-injection. For the other ratings agencies which view Hydro as a stand-alone entity and do not consolidate the debt, the impact is best described by DBRS, which noted: "… a large equity injection by the Province that materially increases tax-supported debt could also put downward pressure on the Province's credit profile"[14]. By providing an equity injection, the Province may help Hydro's books look better, but in the process make its own books look worse, risking the Province's credit rating. Given that Hydro's borrowings are rated as part of the Province's rating, not a specific Hydro rating, the effect would be the opposite of that sought by Hydro as part of the equity injection – future Hydro borrowing could become based on a lowered credit rating which may lead to higher borrowing cost, not lower.

This is not to say that Hydro's new focus is entirely detrimental to customers and rates. A benefit of Hydro's new senior management background is the clear commitment to finally addressing such issues as operating and maintenance costs. As was made clear by the PUB over more than a decade of Board Orders, Hydro had long shown an insufficient focus on cost control and operating efficiency. MIPUG is supportive of Hydro finally responding to the longstanding PUB concerns over staffing levels (going back to at least Order 116/08 in 2008). In particular, Order 5/12 noted that from 2004 to 2011, Hydro's staffing complement grew by 15% (over 900 Equivalent Full-Time positions (EFTs), from 5,769 to 6,669) despite no major change in overall corporate duties. Note that a further 233 increase in EFTs was seen by 2015/16 (to 6,902) per the 2016 interim rate filing Attachment 34. With a heightened private equity and business focused expertise, Hydro may finally be demonstrating diligence for needed cost control.

[13] Transcript, page 1552.
[14] DBRS Rating Report Appendix 4.4, page 2.

ISSUE TOPIC #4:

ISSUE: CHANGE IN UNDERLYING FINANCIALS SINCE NFAT AND THE 2015 GRA

Is Hydro's new financial plan driven by a fundamental change in facts (in terms of new financial conditions or justifiable updated assumptions) since the NFAT proceeding and the 2015 General Rate Application?

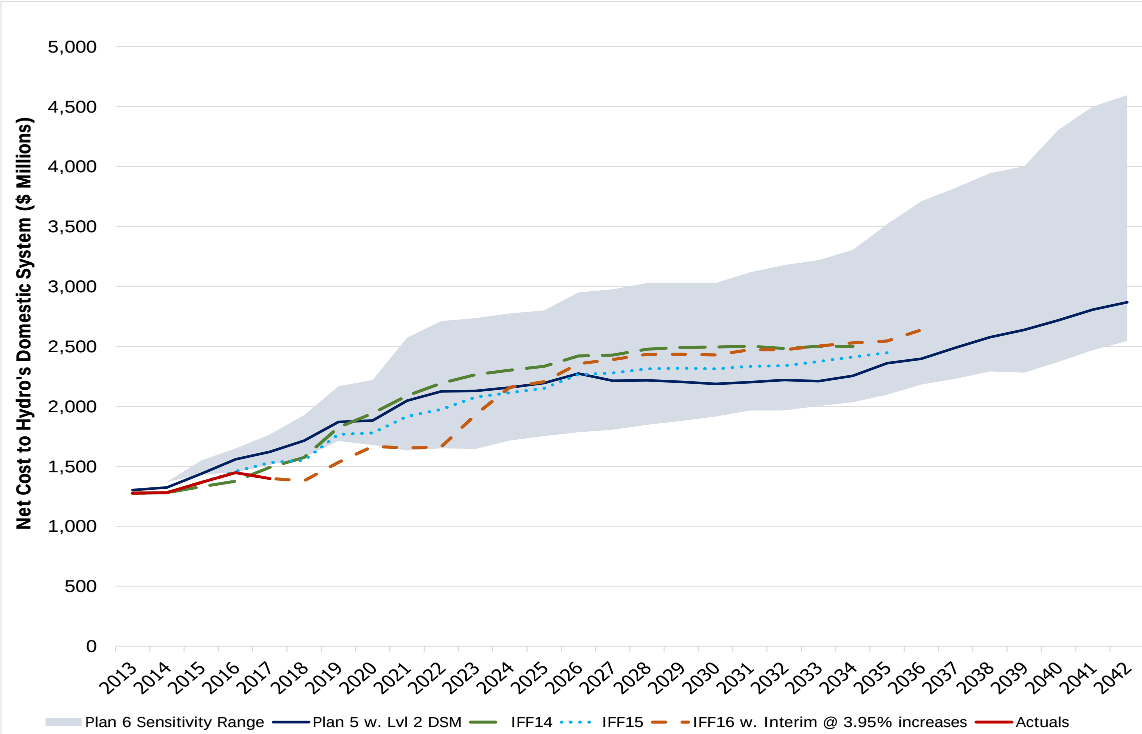
MIPUG SUMMARY AND/OR RECOMMENDATION:

The latest financial forecasts in MH16 and MH16 Update with Interim do not exhibit an overall financial deterioration compared to the NFAT proceeding (IFF12 and IFF13) or the previous 2015 GRA (IFF14). (This is true even using the forecasts as prepared by Hydro for MH16 Update with Interim, notwithstanding that these forecasts are at minimum very conservative on such matters as future export prices, and fail to properly include previous PUB directions on various accounting matters). Further, MH16 scenarios show a massive improvement in the risk profile compared to those past proceedings.

DISCUSSION AND SUPPORT:

At a high level, the costs of Hydro's system can be measured for customers as the total accounting expenses, less the portion funded by exports. On top of these costs, ratepayers typically fund annual contributions to reserves, except in adverse conditions like a drought.

Mr. Bowman produced evidence of how Hydro's costs have evolved since the NFAT (IFF12 and IFF13) review and the last 2 rate reviews (2015 GRA (IFF14) and 2016 Interim Rates (IFF15)) based on Hydro's forecasts at the time (i.e., without reflecting the Board's added conclusions in each proceeding regarding such matters as depreciation accounting). This analysis was provided in Mr. Bowman's direct examination (Exhibit MIPUG-26, page 30) as follows:



No party took issue or offered a differing presentation of this exhibit.

Mr. Bowman described the exhibit as follows:

> MR. PATRICK BOWMAN: … So now moving to those slides. The first slide we go to is slide 30. This is a slide that's reproduced in the background paper B6, page B6 [MIPUG-15]. And what we went to look at is how do the costs, the total costs of Hydro's system that aren't paid by exports compare today to what we considered in a range of outcomes at NFAT?
>
> And we did that for a very specific reason, because I was very concerned that the -- the common sense and the elegance of what was done at NFAT in terms of risk modelling was being lost, and the whole idea that NFAT didn't consider one (1) scenario, it considered multiple -- I think we called them the twenty-seven (27) scenarios at the time -- and it showed a possible future paths, and it considered that things could go adverse on you, considered that all three (3) things, export prices, and interest rates, and capital costs could go adverse on you.
>
> Not all of them considered them going as far to the bad or to the good as they have, but they've gone in offsetting ways. So my basic question is:

> Are we in the cone, or outside of the cone? Have we really blown through the type of risk scenarios that people considered at the NFAT? And so we wanted to consider that a number of different ways.
>
> And the first slide we looked at was what is the net cost to Hydro's system? How many -- how many millions of dollars will be recorded on their -- on their income statement each year to fund the system that is not paid for by exports? And we -- and this is the graph that arose. You'll see NFAT scenarios are in there with a blue line, and the NFAT risk scenarios are in there with the shading, blue or grey, depending on your eyes.
>
> MH-14's around there in green. MH-15's around there in light blue, and MH-16 update with 3.95 percent rate increases are in there in orange.
>
> …
>
> And our basic conclusion was delays and Keeyask, and high water, and lower interest rates have led to improvement in certain years, but the years where -- that matter as you get into Keeyask being online, costs are basically in line with where the NFAT baseline scenarios were, maybe a little higher. Of course, remember, these don't have the accounting changes and the other things we just talked about, or the conservatism built into -- that -- a conservative adjustments that I'll discuss as we move on. [T6080-6081]

To the extent there was a dispute with the analytical approach, Hydro took issue with the fact that the above figure does not represent the full effect on ratepayers since it does not consider changes in the load forecast. Mr. Bowman acknowledged this effect at transcript page 6320 to 6322.

However, Mr. Bowman also noted that this issue had been dealt with in PUB/MIPUG-1 where the Board asked Mr. Bowman to provide a unitized graph ($/kW.h) on the basis of the 2017 load forecast. The response to the Interrogatory notes[1]:

> Part of the decline in the 2017 Load Forecast compared to the 2016 Load Forecast is due to Hydro's projected 7.9% rate increases and corresponding elasticity effects putting downward pressure on load. As a result, updating to the 2017 Load Forecast for a scenario using rate increases which are lower than 7.9% is expected to be pessimistic in terms of loads and revenues.

[1] PUB/MIPUG-1

Mr. Bowman further elaborated on this effect in MIPUG Exhibit 29 (an undertaking to check on figures presented him by Hydro Counsel), which notes:

> Mr. Bowman notes that between the 2013 NFAT load forecast and the 2017 load forecast, looking to the year 2026/27, there was a decrease of 1,722 GW.h (7.1%) as shown in the attached table.
>
> Of this amount, approximately 5.3% is calculated to arise due to the assumed 5 years of 7.9% increases as compared to the rate increases for those years assumed for the 2013 NFAT forecast. Absent this rate effect, the load forecast decrease would be approximately 1.8%. Some portion of this decrease would also be due to increased assumed DSM activities.

Mr. Bowman noted under cross-examination by Hydro counsel that any unitized costs graph would be limited in respect of IFF16 because it would use a load forecast “with the 7.9 percent elasticity, because we don't have a 3.95 load scenario.”[2]

With respect to changes in facts since IFF14, the last Hydro GRA, The Coalition’s expert witness, Mr. Harper, conducted a comparative analysis and reviewed his conclusion that there had been “no significant deterioration evident”[3] citing that (CC-46 slide 11):

CONCLUSIONS RE: IFF16 (@MH15 RATES)

Over All Three Periods Considered

- Interest coverage improves vs. Previous IFFs
- Capital Coverage Deteriorates vs. Previous IFFs
- Debt Ratio In Line With Previous IFFs

-> No Significant Deterioration in Financial Outlook

As a result Hydro’s assertion that there had been a significant deterioration was not supported. Mr. Harper further stated:

> MR. HARPER: … the evidence also notes that extending the 3.95 percent increases to 2033/'34 allows for the achievement of a 75 percent debt ratio just one (1) year later than the previous plans had, i.e., 2034/2035. As a result, while there's been some deterioration, I do not see it as being significant, but rather one that could be managed by adjusting the existing rate plan a small amount. [T5206]

[2] Transcript page 6334.
[3] For example, see CC-46, page 8

The evidence that there has been only limited changes in facts since the previous GRA is also highlighted in MH-93, which compares a modern 20 year scenario (the “MIPUG scenario”) with IFF14 and with NFAT Plan 5, noting the following:

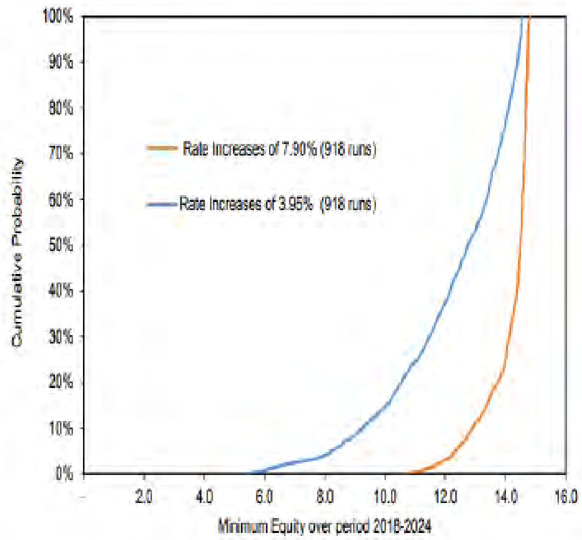
- As to rate increases applied – NFAT used 3.99%/year (with High Keeyask Capital Costs), IFF14 used 3.95%, the new scenario uses 3.57%
- As to net losses, NFAT assumed 8 years of net losses totalling $638 million, IFF14 also showed 8 years of net losses totalling $977 million, while the new scenario shows only 6 years of net losses totalling $418 million.
- As to minimum equity, NFAT showed a minimum of 8%, IFF14 a minimum of 10%, the new scenario a minimum of 12%.
- The only metric on which the new scenario is not improved compared to NFAT and IFF14 is maximum net debt – NFAT at $21.6 billion, IFF14 at $23.2 billion, the new scenario at $25.0 billion. However, with the ongoing reductions in interest rates, the impact of this debt does not result in adverse impacts on all of the above noted measurements.

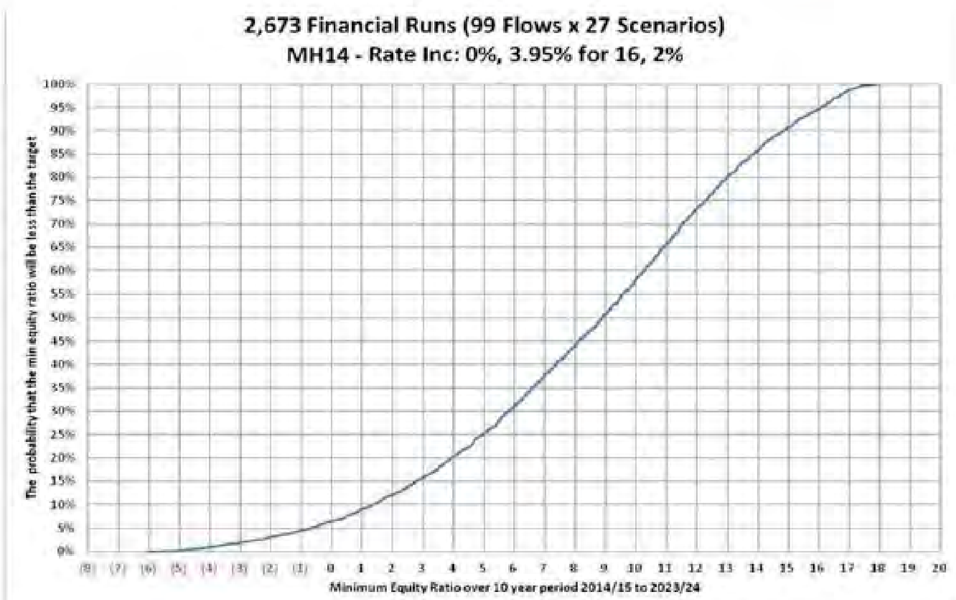
Finally, there is the issue of risk. As set out in MIPUG Exhibit 27 (reproduced below), the current IFF16 (at 3.95% rate increases) which is the upper part of the figure, shows a materially improved situation with regard to the low point that the equity ratio may reach. IFF14 (the lower part of the figure) was considerably worse from a risk perspective. Mr. Bowman described the figure as follows:

> MR. BOWMAN: … So if you compare the upper graph, which we just talked about, you can see the distribution of possible minimum retained earnings -- minimum debt equity ratio over that period and compare it to the bottom graph about the possible futures that IFF14 was looking at.
>
> We now say that our P1 scenario will lead us to about 5 percent equity, if we stick with the 3.95. If you look down at the IFF14, that was approximately the P30. Thirty percent of the possible futures had debt equities worse than that and many of them drop below zero. Some of them as low as negative 6.
>
> So what's happened by letting time go on, getting interest rates locked in and with the evolution in things like export markets is we have pulled in this, in a massive way, this bottom end risk that Hydro faced when we sat here at the last GRA. And as we continue to lock in debt that will continue to tighten.
>
> We've also lost some of the top end. We no longer have scenarios that will lead us to 18 percent debt equity at the worst, because we didn't have

> the stunning export markets and flood conditions, or whatever else would lead to have led to those type of scenarios. But that's the resolution of risk we see as you let the time unfold and you let some of the key variables that are being locked in overtime today get resolved. [T6066-6067]

Uncertainty Perspective Minimum Equity Ratios over the Period to 2024 – MH14 compared to MH16 (with 3.95% and 7.9% rate increases) [Appendix 4.1, page 116 & Appendix 4.5, page 75]





Approximate Minimum Equity Ratio Reached Over the Interval to 2024 (%)	P01	P25	P50	P75	P99
MH14	- 6	5	9	12	18
MH16 with 3.95%	5	11	12	13	14
MH16 with 7.9%	11	14	14	14	14

In terms of Hydro's financial metrics, Hydro's Final Argument noted that without a 7.9% scenario, Hydro's financial targets were missed in many years over the next 10 (shown in red on the following slide 51 from MH-136, as follows:

- 3.95% rate path does not come close to meeting targets in any event

Financial Ratios:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Equity Ratio (Target > 25%)										
MH16 Update with Interim	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
MH15 Rates	15%	14%	13%	13%	13%	12%	12%	11%	10%	10%
Capital Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.40 x	1.48 x	1.47 x	1.88 x	2.34 x	2.25 x	2.37 x	2.34 x	2.20 x	2.29 x
MH15 Rates	1.39 x	1.33 x	1.15 x	1.36 x	1.59 x	1.30 x	1.21 x	1.20 x	1.10 x	1.18 x
EBITDA Interest Coverage Ratio (Target > 1.80x)										
MH16 Update with Interim	1.54 x	1.71 x	1.72 x	1.84 x	2.01 x	2.03 x	2.08 x	2.22 x	2.24 x	2.36 x
MH15 Rates	1.53 x	1.61 x	1.54 x	1.58 x	1.64 x	1.54 x	1.47 x	1.52 x	1.49 x	1.54 x

Other Metrics:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
EBIT Interest Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.10 x	1.21 x	1.20 x	1.31 x	1.45 x	1.38 x	1.36 x	1.47 x	1.45 x	1.54 x
MH15 Rates	1.10 x	1.13 x	1.03 x	1.07 x	1.12 x	0.95 x	0.83 x	0.86 x	0.82 x	0.88 x
Net Debt										
MH16 Update with Interim	$ 18 473	$ 20 743	$ 22 407	$ 23 296	$ 23 609	$ 23 388	$ 22 831	$ 22 201	$ 21 613	$ 20 947
MH15 Rates	$ 18 474	$ 20 825	$ 22 657	$ 23 809	$ 24 496	$ 24 761	$ 24 811	$ 24 877	$ 24 994	$ 25 060

What Hydro's Final Argument ignores is that even under the 3.95% scenario (MH15 Rates) shown above with material red coloration, the pattern of financial target achievement remains almost identical to the IFF14 scenario, as shown in KPMG's report (Hydro's GRA Appendix 4.1, page 25), as shown below. This KPMG figure specifically indicates that white cells miss Hydro's financial targets by more than 10%, while coloured cells are within 10% of the target (note that even KPMG does not expect 100% of targets to be met to merit colouration):

Figure 3-8B: Manitoba Hydro Financial Targets Data from Forecasts under IFF14

Projections from IFF14 (reflects within 10% of target)			
Year	Equity Ratio %	Interest Coverage	Capital Coverage
2015	23	1.17	0.99
2016	19	1.17	1.05
2017	17	1.07	0.96
2018	16	1.07	1.13
2019	15	0.94	0.94
2020	14	0.92	0.86
2021	13	0.88	0.87
2022	12	0.86	0.98
2023	11	0.87	1.11
2024	11	0.92	1.24
2025	11	0.97	1.27
2026	11	0.99	1.31
2027	12	1.07	1.47
2028	13	1.12	1.57
2029	14	1.20	1.68
2030	16	1.30	1.91
2031	18	1.41	1.99
2032	21	1.52	2.14
2033	24	1.60	2.22
2034	27	1.70	2.34

Source: from Projected Consolidated Financial Statements in Manitoba Hydro Integrated Financial Forecast (IFF14) 2014/15 - 2033/34, December 2014

Note that although Hydro's Final Argument table shows that the EBIT interest coverage (target >1.2) is not met over the first 10 years in IFF16 (i.e., all values are red in Hydro's Final Argument table), it was similarly not met under IFF14 (i.e., all values are white in the KPMG table above). Perhaps most interestingly, Hydro's calculations show that under 3.95% rate increases, the Capital Coverage Target is now expected to be met in all years except 2019/20 (1.15), 2025/26 (1.10), and 2026/27 (1.18), KPMG would consider each of these to be met using the test of "within 10%" – in contrast, under IFF14 (the KPMG table), the Capital Coverage target of 1.2 was missed in almost all of the first 10 years.

ISSUE TOPIC #5:

ISSUE: THE BENEFITS OF THE 7.9%/YEAR RATE PLAN ARE OVERSTATED

Does the 7.9% rate plan provide benefits as asserted by Hydro, and are these benefits likely to occur?

MIPUG SUMMARY AND/OR RECOMMENDATION:

The 7.9% rate path does not appear to provide benefits to Hydro in terms of access to capital, which does not appear to be under threat. The 7.9% will not result in reversing the S&P decision to no longer classify Hydro as self-supporting, nor will it necessarily even result in a reduced cost of borrowing compared to the 20 year plans.

On the customer side, the purported benefits of paying higher rates for Hydro to avoid some government-guaranteed debt at rates as low as 3% interest, in order to secure lower rates in the future (from avoided interest costs) appears to ignore that the value of such funds to the ratepayers own uses (be they residential low income, non-profits, municipal governments, or businesses and industries) likely exceeds a 3% annual value.

DISCUSSION AND SUPPORT:

In respect of the benefits of the 7.9% plan, Hydro's summary of purported benefits focuses on hypothetical future rate decreases to customers (see Issue Paper #2 In respect of MH Exhibit-64 and the "Why Are We Doing This?" slide 30), reduced risk of rate shocks in the event of adverse conditions like drought (see Issue Paper #2 in respect of net profits occurring during a drought), and on ensuring Hydro can present a strong picture to capital markets. This latter point builds on the idea of being "self-supporting" to aid with the access to, and cost of, new borrowing. Hydro also focuses on how ratepayers will save themselves future interest costs by building more reserves within Hydro.

The issue of access to capital was addressed by Mr. Colaiacovo in his direct examination, where he noted there is little risk on Hydro's ability to access credit markets:

> MR. PELINO COLAIACOVO: So the next section, Mr. Chair, is to talk about capital markets, which have been much discussed through the hearing process so far. Manitoba Hydro gets all of its long-term debt from the Province of Manitoba and doesn't directly interact with the capital markets in general.

> …
>
> So technically, the lender to Manitoba Hydro is the Province of Manitoba, and the Province of Manitoba, then, in turn interacts with the capital markets.
>
> Is there any practical risk that Manitoba Hydro could not get the long-term debt money that it needs? And I think the only short answer to that question is no. Now, a caveat on that is, in fact, there has been in living memory, in recent memory, a time when the capital markets froze, and that was in September of 2008, and I was in the middle of three (3) deals that month which did not close until after January.
>
> And the capital markets did freeze in that one (1) instance, but that's pretty much the only instance in the memory of most people who work in the capital markets and otherwise, is there a practical risk that Manitoba Hydro cannot get that? No, there is not, because its debt comes from the Province, and the Province raises money week in and week out on the capital markets. [T4883-4884]

A similar statement about capital market was set out by Hydro's treasurer at the time of NFAT, which in MIPUG's view has in no way been negated by the proceeding to date:

> MR. MANFRED SCHULZ: […] We are undertaking large pieces of financing now. We have no reason to believe that there's going to be any interruption to the liquidity, and in fact, what we're hearing from many of the investors is that, Yeah, of course your ratio goes down through this, because you're taking on more debt as part of the investments, but what are you getting out of it, as Mr. Rainkie said, is a revenue generating asset, which is very positive for them, because they have stability cash flow. All of that reduces the risk and increases our ability to access markets, so. The long and short of this is, you know, further to the point that, you know, the hypothetical, I mean, this notion that somehow we're not self-supporting, it's a complete capital 'H' hypothetical in our minds.[1]

In short, the evidence suggests there is no serious threat to Hydro's ability to borrow arising from the current financial situation, much less a threat that requires the 7.9% rate increase plans.

[1] NFAT transcript Page 3104, line 13 to Page 3105, line 3 reproduced in Attachment C to Bowman pre-filed testimony in the current proceeding (MIPUG Exhibit 13).

In respect of the province, Hydro made a strong statement that a duty of avoiding debt is owed to the Province, during its Policy Panel direct evidence at transcript 257:

> MR. JAMES MCCALLUM: … Taking steps to minimize our risk to the province is simply honouring our deal with the taxpayer and acting in our own and our customers best interest. [T257]

However as noted by Mr. Bowman, there is no reasonable concept of a duty owed to the Province to avoid debt associated with capital projects that the Province directed be built and then subsequently expressly approved for construction:

> MR. MATTHEW GHIKAS: Now, you've also referenced in that passage there, the fact that government charges a guarantee fee.
>
> You'd agree with me, I assume Mr. Bowman, that the fact that the government charges a guarantee fee isn't a license for Manitoba Hydro to act in ways that would harm the province's credit rating?
>
> MR. PATRICK BOWMAN: I think there are a lot of things that stand in the way of Manitoba Hydro acting in ways that would be imprudent but I don't think the guarantee fee should be ignored when you're considering Hydro and the province as a -- in terms of the relevance of Hydro's debt.
>
> MR. MATTHEW GHIKAS: And what I asked you, Mr. Bowman, was whether the fact that government charges a guarantee fee is a license for Manitoba Hydro to act in ways that would harm its credit rating.
>
> Is that how you view the guarantee that because the government has been paid that they shouldn't be concerned about what impact Manitoba Hydro might or might not have on their credit rating?
>
> MR. PATRICK BOWMAN: Mr. Ghikas, maybe I'm getting caught up on the idea of licensed. The -- Hydro's building a dam that the government approved at building; that's the reason the government has control in decisions over Hydro's major capital spending in the Act. Hydro can't go off and sign major export contracts or build major new generation without the government signing off on it because it's going to be a future commitment on the government's borrowings. That's why they give the approvals. It's unfolding according to the approvals.
>
> So this -- I guess license sort of implies that the teenager with the car keys or something. It's -- I'm sorry, if I get stuck up on a word. [T6266-6268]

There is no contention being made today that Hydro ought to act imprudently to the detriment of the Province's credit rating. However, there is also no evidence that even if Hydro acted prudently, yet adversely affected the Province's rating, that it would be a net short-term or long-term negative effect on the Province compared to not having Hydro's debt on its books, as noted in Mr. Bowman's pre-filed testimony (MIPUG Exhibit 13):

> In regard to protecting the Province of Manitoba finances, there is no indication that Hydro debt is causing the Province to face higher borrowing costs. If anything, Manitoba's spread over other provinces (Ontario) has decreased in recent years. In addition, even if higher borrowing costs for the Provincial Government were occurring, there is no indication that the costs to the Province exceed the $230 million/year scheduled to be paid by ratepayers in "debt guarantee fees" once Keeyask is in service, much less the $1.3 billion paid from 2002 to 2017 when there were no net costs to the Province of having provided the guarantee.[2]

Finally, if there were a finding that Manitoba Hydro were not self-supporting, there was evidence provided that this would not necessarily translate in higher debt costs, as noted by Mr. Colaiacovo and Dr. Yatchew. Starting with Mr. Colaiacovo, he noted that loss of self-supporting status did not, in practice, lead to an increase in Manitoba's borrowing spread:

> MR. PELINO COLAIACOVO: Standard & Poor's changed their methodology in 2016. They decided that 'self-supporting' did not any longer mean covering all of your costs through rates, which is what DBRS and Moody's defined 'self-supporting' as.
>
> …
>
> Did it actually change anything that Standard & Poor's changed their definition? I would argue that there is no evidence that they had any impact on the market. You've already seen in my report, and others have looked at the same issue of spreads. There has not been -- there was not substantial impact on the cost of credit for the Province of Manitoba when Standard & Poor's made that announcement. It was a departure on their part from their own policies. They shifted the definition. It resulted in some different numbers.

[2] pages 1-3 to 1-4.

> Manitoba Hydro has chosen to highlight that change in its application in some of the added materials. I just don't think that it's particularly valuable to focus on that one (1) company's choice of what the definition of self-supporting would mean as a driver of rate policy in Manitoba. [T4897-4898]

Comments from Dr. Yatchew also noted the hypothetical nature of the issue, and the potentially immaterial impact to the Provincial ratings, which are instead based on the strength of the overall Provincial economy:

> MR. KEVIN WILLIAMS: Would you agree with me that the probability that market interest rates will increase over the near term is greater than the probability that the market interest rates will decline over the near term?
>
> DR. ADONIS YATCHEW: Yes, and we've been waiting for those increases for a long time and they haven't happened so. We'll see how quickly they do happen.
>
> MR. KEVIN WILLIAMS: Thank you. Would you agree with me that increases in Manitoba Hydro's borrowing costs will negatively impact on its earnings?
>
> DR. ADONIS YATCHEW: Yes.
>
> MR. KEVIN WILLIAMS: Would you agree with me that if Manitoba Hydro's earnings decline, it increases the probability that its credit rating will be downgraded?
>
> DR. ADONIS YATCHEW: In general terms, yes. The only additional qualification I would put in is that Manitoba Hydro, as many large corporations, hold a portfolio of debt staggered over various maturity dates. So with an increasing interest rates, it might not translate that quickly in terms of the costs that Manitoba Hydro has to incur in servicing its debt.
>
> MR. KEVIN WILLIAMS: Fair enough. And other people have spoken to the debt management strategy at Hydro and your response is completely consistent with that.
>
> Would you agree with me, sir, that rate increases by this Board would reduce the potential risk of a credit downgrade to Manitoba Hydro when compared to the risk of such a downgrade in absence of a rate increase, if you held all other factors equal?

DR. ADONIS YATCHEW: That's key, holding all other factors equal.

MR. KEVIN WILLIAMS: I added that right at the last moment.

DR. ADONIS YATCHEW: Let me just ensure that I know what you're holding constant here. So, let's say that there's a high rate increase and just to think in terms of the longer-term --

MR. KEVIN WILLIAMS: Yep.

DR. ADONIS YATCHEW: -- the 50 percent real increase. That also has an impact on sales. So, it might -- it's not clear whether it's going to have -- how much of an impact that would have on net income. An increase in rates increases revenues, but a reduction in sales reduces revenues. So, on balance because of the inelastic demand, yes, I would expect that revenues would increase as a result of an increase in rates, but there are some offsetting things that you can't really hold constant when you're increasing rates.

MR. KEVIN WILLIAMS: Right. But I take it, sir, that you would agree that the larger the increase that's granted that there's a lower risk of a credit downgrade associated with that?

DR. ADONIS YATCHEW: In general terms lending agencies are very much interested in whether you can pay the interest costs. And if you have a larger cushion that risks goes down, the risk of a downgrade goes down, but we're really talking here in very abstract terms.

MR. KEVIN WILLIAMS: Right.

DR. ADONIS YATCHEW: Abstract in the sense that we'd have to put a lot of numerical analysis which financial analysts do, including the overall health of the Manitoba economy and the understood fact that it's backing the debt. [T4544-4547]

Finally, even Hydro has acknowledged that the 7.9% rate path is not about achieving self-sustaining status from S&P and that such status should not be targeted, noting in MIPUG/MH-II-17d:

QUESTION:

Is it Hydro’s objective to be viewed as self-supporting by S&P under the current criteria? If so, what is Hydro’s target date for such recognition?

> **RESPONSE:**
>
> No. It is not Manitoba Hydro's objective to be viewed as self-supporting under the S&P criteria.

In short, the issue of benefits of Hydro's 7.9% plan are speculative, uncertain, and potentially of very little impact. The only definite direct impact identified is a reduction in future interest costs[3] and in building up Hydro's retained earnings balance:

> MS. LIZ CARRIERE: Mr. Hacault, you're absolutely right, and we can be wrong. Our interest rates may be lower. But if the PUB -- it will be so gracious as to award us 7.9 percent, and I was thinking about this morning as we were being crossed by Mr. Williams, and he pointed out that we don't pay dividends.
>
> So, any rate that it was awarded to us -- and if we are wrong in these forecasts, the revenue isn't going anywhere. It's not going to a shareholder that's earning a 10 percent rate of return. It's staying in retained earnings, and it's there for the ratepayers' benefit in the future. [T1586-1587]

However this very concept was described by Mr. Colaiacovo as "equity is essentially dead money. It earns no return, but nevertheless has been taken out of the hands of ratepayers who could otherwise use it"[4]. This equity, derived from higher than needed rates, arises from using ratepayer funds to avoid low cost government-guaranteed borrowings at perhaps 3%[5]. Clear evidence has been provided to the Board through multiple public presentations that ratepayers (be it individuals, non-profits, local governments, associations, small businesses or industrial users) have significant alternative uses for these same funds that is targeted at a much higher value to the economy, and net returns to the customer, than 3%.

[3] Manitoba Hydro Final Argument, MH Exhibit MH-137, page 28

[4] Exhibit CC-17, page 55.

[5] Per Exhibit MH-68, page 64.

ISSUE TOPIC #6:

ISSUE: ASSESSMENT OF THE RISKS AND IMPACTS OF HYDRO'S PLAN

Has Hydro's plan been fully and properly assessed and vetted for the potential adverse impacts on Hydro's revenues, on the provincial economy, and on future ratepayer funds?

MIPUG SUMMARY AND/OR RECOMMENDATION:

Hydro's plan has not been properly assessed for its impacts on ratepayers and the economy. First, there is evidence Hydro has underestimated the degree to which its loads will be undermined by the 7.9% rate plan, and as a result Hydro may cause more damage to its own revenues than anticipated. Second, Hydro has led no study on the economic impacts on the provincial economy arising from its plan. The work that is available indicates Hydro's plan will draw material amounts of funds out of the provincial economy for the sole purposes of carrying a smaller debt balance (meaning these funds will not be spent by Hydro in other ways to stimulate the economy). The magnitude of the funds being drawn out is very large – larger than the contentious 1% PST hike. Finally, evidence from Hydro's history notes that if Hydro did secure rate increases that led to material net income as projected, the risk of "moral hazard" in the form of future increases in government charges cannot be ignored.

DISCUSSION AND SUPPORT:

Hydro's plan for 7.9% rate increases to achieve a 75% debt ratio by 2026/27 is predicated on gaining sufficient revenues to fund the build-up of equity by over $3.5 billion over this ten year period. This is in addition to funding all of the costs of the new major projects as they come into service. As noted by Mr. Bowman:

> MR. PATRICK BOWMAN: … The immediate reaction on receiving and reviewing the GRA is that it reflects a fundamental change in perspective from Hydro. It's critical to make clear that this is, at its core, can be understood as a difference between a ten (10) year versus a twenty (20) year outlook. And if -- I'm trying to find the right words, I noted there that every other issue is effectively subservient subverted to this issue. Once you put in place a determination that you need to get to 25 percent equity within ten (10) years, every other issue pales because you've just set yourself the challenge of finding an extra 3 1/2 billion dollars above costs within ten (10) years, and that trumps everything. [T6016-6017]

That $3.5 billion is derived from the capital costs of new major capital projects of $5 billion for Bipole III, $8.7 billion for Keeyask, plus Manitoba-Minnesota Transmission Project (MMTP) and Great Northern Transmission Line (GNTL). Mr. Bowman noted:

> MR. PATRICK BOWMAN: …when you have $14 billion of capital coming online, and you decide that you need to fund 25 percent of it through reserves, meaning charging rates that are higher than cost by -- to build those reserves, the number you derive is you need 3 1/2 billion dollars of extra funding in Hydro, extra rates being charged to people over a decade to build up that 25 percent, over and above the cost of those assets. [T6073-6074]

A critical aspect of whether Hydro will in fact yield that degree of revenues from domestic ratepayers relates to applying an appropriate concept of "elasticity" – the sales volume response to a change in price. There is a clear concern that any such estimate applied to Manitoba loads today is highly speculative, due to a complete lack of experience in Manitoba with rate increases at four times the rate of inflation as is now proposed. Consider the example offered by Dr. Yatchew:

> DR. ADONIS YATCHEW: … Let me give an example. In a completely different setting, suppose you want to know how a population will respond to dosages of a particular drug, okay. And you've observed over time how that population has responded over, let's say, low dosages of that drug.
>
> So you can interpolate, you can say, well, if we increase -- if we increase the dosage by 5 percent or reduce it by 6 percent, you can get a pretty good idea of what the response would be because you've observed behaviour in that range.
>
> Now, suppose you want to increase the dosage by 50 percent and have not chosen that number accidentally. You're going to increase the dosage by 50 percent and you're going to extrapolate from your population, which has never faced that higher dosage; that is going to be -- that's going to limit the quality and reliability of your analysis. At the very least, you would want to look at other populations which have faced these higher dosages. They should also be helpful in informing how your population is going to respond.
>
> So, even very good time-series data for one (1) location that doesn't have the variation in, let's say, energy prices or electricity prices that is being anticipated or is being considered, even very good time-series data of that type won't be quite as -- you won't be quite as confident as if you've

> actually tested your -- that kind of modelling against the much more general experience elsewhere. [T4419-4420]

Dr. Yatchew's evidence highlights a degree of uncertainty with respect to Hydro's assumptions. While Dr. Yatchew notes that Hydro estimates of elasticity of -0.27 is "within the range of the estimates that are out there"[1], he recommends that Hydro assume a much higher long-term price response of -0.35 for the residential and commercial sectors and -0.5 for the industrial sector[2]. Further, Dr. Yatchew notes that Hydro's rate increases "may discourage future industrial investments, particularly in very electricity intensive industries"[3] and notes that the literature yields elasticities as high as -1.4 for the industrial sector attributed to electricity intensive industry in low-price states[4]. This suggests a price response (i.e., reduced load) from industry recommended by Dr. Yatchew at double the Hydro estimate, and up to five times as high if the electricity intensive jurisdiction studies are to be relied upon. Note that the Board's Independent Expert Consultant witness from Daymark similarly concluded with respect to the risk of load reductions among industrial customers: "Our recommendation or our observation is that in the short term it may be greater response than is included in the current forecast in the short term."[5]

In summary, there should be a significant basis for concern that under the 7.9% rate increase path, Hydro will undermine its own loads (particularly industry) far more than presently assumed.

In terms of economic impact, Dr. Yatchew noted that broad provincial economies can respond to certain types of price shocks but that this may not be true for the key affected industries and communities:

> DR. ADONIS YATCHEW: … In the event that there are large electricity price increases, such prices are -- I think such increases are improved over the coming years. I realize this is a two (2) year window right now that we're looking at, but if they continue as Manitoba Hydro has indicated it needs, the net effect on GDP eventually may be modest. But in the interim, there are likely to be significant adjustment costs in some locations, particularly those that are heavily dependent on an industry that is sensitive to electricity prices, there could be large local impacts on employment, on incomes, and on output.

[1] Transcript, page 4421
[2] Yatchew pre-filed testimony, Exhibit AY-1, page iii.
[3] Yatchew pre-filed testimony, Exhibit AY-1, page 22.
[4] Yatchew pre-filed testimony, Exhibit AY-1, page 26.
[5] Transcript page 4004, lines 7-10.

> These are not rate increases of the same magnitude as the energy price shocks in oil of the 1970s. However, given that in the short-term, demand for electricity is highly price inelastic, the steepness of the projected rate increases will impose a significant burden, particularly on households, businesses, and institutions that do not have access to substitutes. [T4438-4439]

Customers that do not have access to substitutes would include those located where there is no natural gas (e.g., northern mines, paper), those that use an electrolysis process (e.g., the chemical industry), those that require electricity for non-motive motor loads (e.g., pipeline pumping or compression), those that use arc furnaces (e.g., the steel industry) or those that use cooling compressors (e.g., the meat processing industries). Additionally, for those that could switch to natural gas there is uncertainty around expenses related to a pending carbon tax. In short, the above reference from Dr. Yatchew should reasonably read to include effectively all Manitoba industrial loads.

The pre-filed testimony of Messrs. Osler and Forrest (MIPUG Exhibit 14) also noted in regards to the appropriate design of rate proposals, the need to be attentive to broad economic policy goals:

> **General policy goals to avoid material adverse impacts on customers and the Manitoba economy** – very high and unexpected rate increases act to jar near and long-term customer confidence in this province's electricity services, and can lead to unintended consequences, including discouragement of new loads, and reductions in current loads and subsequent revenues that frustrate Hydro's revenue objectives; in addition, significantly higher than inflation rate increases will impose material adverse economic impacts on the overall provincial economy which, in the current Manitoba context, would be concurrent with the end of the economic stimulus related to the construction of the new Hydro assets. (MIPUG-14, pg. 3-1)

In terms of the impacts on Manitoba, Hydro indicated it had not conducted an economic impact assessment of the rate proposals and their expected effect on Manitoba:

> MR. BOB PETERS: Would it be correct, Mr. Shepherd, that Manitoba Hydro hasn't conducted an analysis of the rate impacts on the various customer classes in terms of what their economic impact would be?

> MR. KELVIN SHEPHERD: I think it would be fair to say that I haven't seen an analytical impact study. [T347]

At the same time, Mr. Markowsky, the witness on behalf of the City of Winnipeg, noted that he had previous been a Senior Economist for Manitoba Hydro. Mr. Markowsky noted under cross-examination that Hydro has "on the order of five (5) economists in the economic analysis department"[6] and that in respect of macroeconomic analysis of the impacts on the Manitoba economy they had internal capabilities as well as leading work "in some cases, that was outsourced to the Manitoba Bureau of Statistics for input/output modelling."[7]

> MR. ANTOINE HACAULT: So what you're telling me is that to the extent that those economists wouldn't have been able to do it themselves, they certainly would have been able to direct such a study to determine the economic impact of the rate request, firstly, and of any plan that Manitoba Hydro may put going forward?
>
> MR. TYLER MARKOWSKY: … you know, if the department was directed to conduct a macroeconomic analysis, or an impact analysis of something, I am sure that, you know, a decision would have been made to determine if that could be done in-house or whether it would -- needed to be outsourced. And those kind of requests did come. [T6507-6508]

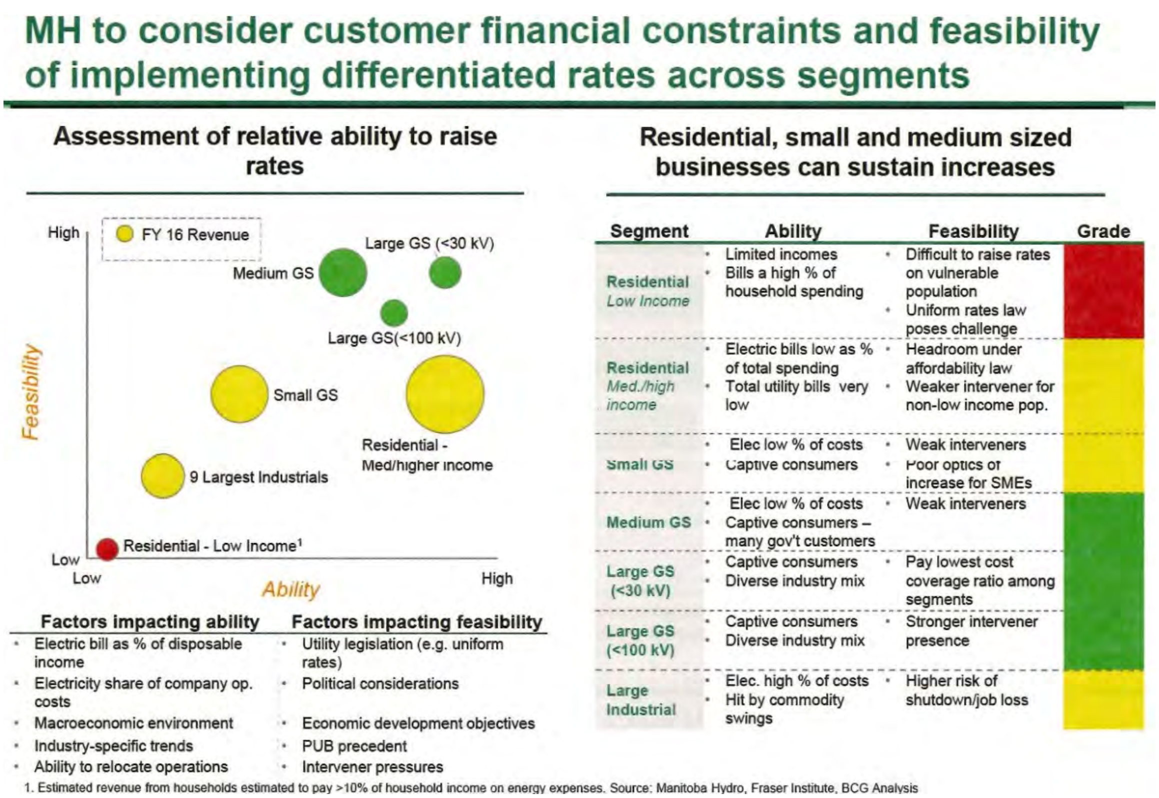
It is clear that Hydro did not make a request of its' internal economists nor external resources to determine the economic impacts of the new and unprecedented rate proposal. This is unfortunate, as there is now extensive evidence before the Board regarding the potential for the rate increases to cause adverse effects on the economy, but without a single thorough analysis from Hydro about the scale of these impacts. Note that the potential for adverse impacts must be acknowledged to be very large, as cited by Mr. Bowman in his pre-filed testimony:

> Along with potential industrial impacts related to risks of shutdown/job loss, no information is provided by Hydro regarding the basic broader economy impacts of the higher revenues being charged by Hydro solely for the purpose of Hydro's own debt reduction. Consider that the extra amounts paid by domestic ratepayers to Hydro over the 2018/19 to 2027/28 period (10 years) under the 7.9%/year trajectory versus 3.95%/year scenario[8] is $3.616 billion, or an average of $362 million per year. This is simply the incremental rates charged over and above the 3.95%/year scenario on average during this decade (and does not include GST, PST and where relevant City Tax which would increase this value

[6] Transcript page 6507, lines 4-6.
[7] Transcript, page 6507, lines 15-16.
[8] Comparing Appendix 3.8 to PUB/MH I 34 Attachment 2.

by a significant amounts). For perspective, total amounts collected in the province in 2017/18 for Manitoba Corporations Tax is $334 million, Payroll Tax is $477 million, and 1% on the Provincial Sales Tax is $294 million[9]. The net impact from Hydro's rate changes on the economy could be more significant than these examples, as government revenues are in part used to fund activity within the Manitoba economy with associated multiplier benefits – the Hydro increases are solely slated to pay down debt, which does not generate production in the economy. (MIPUG-13, pages 4-11 - 4-12).

Further, Hydro's Board advisers, Boston Consulting Group (BCG), similarly informed Hydro of the potential for adverse economic impacts when it noted there was a low "feasibility" to raise rates on low income customers and on large industrial customers, including "a higher risk of shutdown/job loss", as shown in the following slide from the BCG presentation[10]:



Segment	Ability	Feasibility	Grade
Residential Low Income	• Limited incomes • Bills a high % of household spending	• Difficult to raise rates on vulnerable population • Uniform rates law poses challenge	
Residential Med./high income	• Electric bills low as % of total spending • Total utility bills very low	• Headroom under affordability law • Weaker intervener for non-low income pop.	
Small GS	• Elec low % of costs • Captive consumers	• Weak interveners • Poor optics of increase for SMEs	
Medium GS	• Elec low % of costs • Captive consumers – many gov't customers	• Weak interveners	
Large GS (<30 kV)	• Captive consumers • Diverse industry mix	• Pay lowest cost coverage ratio among segments	
Large GS (<100 kV)	• Captive consumers • Diverse industry mix	• Stronger intervener presence	
Large Industrial	• Elec. high % of costs • Hit by commodity swings	• Higher risk of shutdown/job loss	

[9] From Details - Estimates of Revenue, per page 143 of the 2017 Manitoba Restated Estimate of Expenditure and Revenue http://www.gov.mb.ca/finance/budget17/papers/r_and_e.pdf, as cited in MIPUG-13, page 41.

[10] PUB-MFR-72 Attachment, BCG Presentation from August 25, 2016, pdf page 468 of 615.

In terms of the practical impact, the issue of effects on industries was explored with Dr. Simpson under cross-examination:

> MR. ANTOINE HACAULT: Now, with respect to any northern communities where these major employers would be mines or pulp and paper mills, would those micro economies have much flexibility in absorbing or creating jobs if a plant were to close?
>
> DR. WAYNE SIMPSON: I think you're asking how would one (1) industry town cope with the closure of its main industry? Not well. [T4788]

This type of load decline also lead to a utility issue that Dr. Yatchew noted was sub-optimal:

> DR. ADONIS YATCHEW: … What I'm saying here is that pricing electricity at high levels if it's higher than necessary, for example, leaves assets underutilized and that's the meaning of the sub-optimality.
>
> Let me just finally say that with lumpy assets, you're always going to have a period of time when some portion of them are not being used. They're not being fully used; that's just the reality of bringing on a facility that will be fully utilized a few years down the road, but not yet. So there's you're going to have that underutilization problem. The price effect exacerbates that. [T4466]

Perhaps the most potent example of the sub-optimality comes from the presentation of Chemtrade Logistics Group Vice-President Mr. Michael St. Pierre. In this proceeding, one of the things that Hydro has expressed is a concern about the prices it can get for exports, and how this is increasingly a low value opportunity-market-based price in Hydro's forecasts. However, the electrochemical industry (such as Chemtrade) offers Hydro a preferred manner to export power, by effectively mixing it with salt and water: "Sodium chlorate is produced by an electro chemical process whereby sodium chloride, or table salt, is combined with water and is then exposed to electrical power. This process is used -- uses electricity to transform the salt into sodium chlorate. The importance of electrical power to our process cannot be overstated."[11]

> MR. MICHAEL ST. PIERRE: (Chemtrade): … We believe Manitoba has a competitive advantage with a low cost, green electricity -- electricity supply and should use this as a tool to drive economic growth in the province in a fast changing marketplace.

[11] Transcript page 7717.

> Finally, in addition to those statements applicable to all industry, we believe that the electro chemical industry must continue to be encouraged to produce in Manitoba. At a time when Hydro is worried about the out-of-province sales of power, the production of chlorate in the province for sales outside is effectively a long-term efficient sale of power to geographies not reachable by Hydro directly.
>
> The industry has, and can continue, to facilitate these notional power sales without any additional investment by Hydro and infrastructure to reach those distant geographies. The battle cannot be between Manitoba Hydro and Manitoba industry in the zero-sum game. [T7725-7726)

This option to receive firm power prices for Hydro's power, along with the jobs that come with it (which are far larger than the jobs that come from closing manufacturers and exporting the power to Minnesota), and in this manner achieve a quasi-power export requiring no new transmission and no direct connection to the ultimate market only exists so long as Chemtrade and other chemical industries remain competitive in Manitoba.

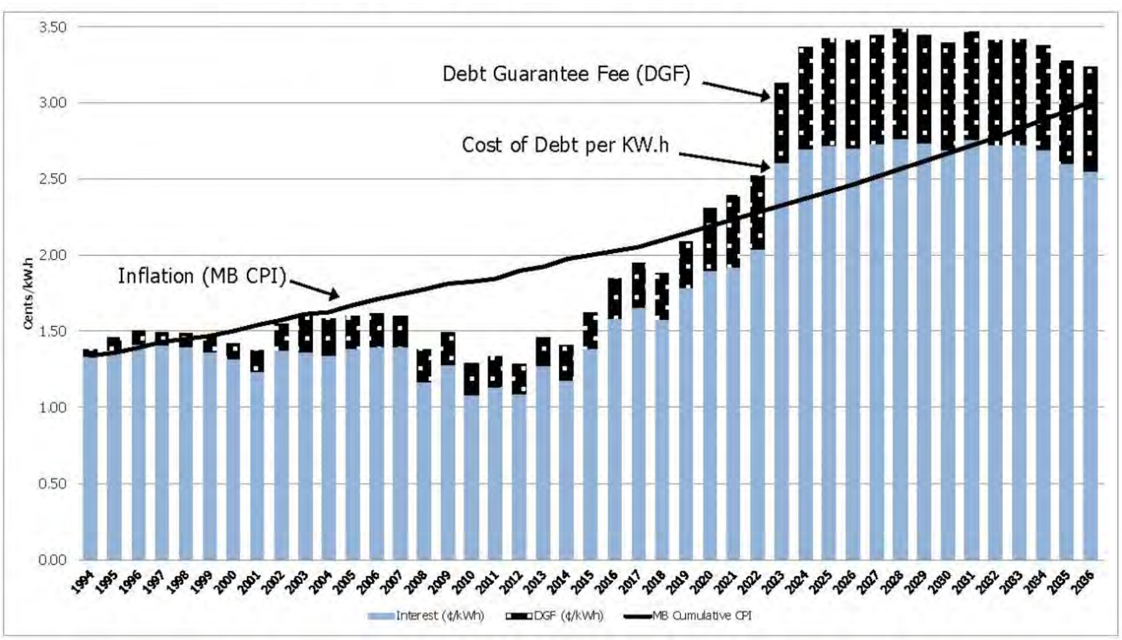
The final adverse impact that is not considered as part of Hydro's plan is the issue noted by Mr. Forrest as "moral hazard", or the temptation that arises for Hydro and government to act differently when large equity surpluses are being generated within Hydro off of ratepayers:

> MR. GERALD FORREST: … During my term as Chair, when we saw the financial wellness of the Corporation or Crown corporations improve, we also saw that the government from time to time made additional demands on the financial resources of those corporations. And, indeed, it was at one (1) of the hearings years ago where Dr. Williams was in attendance where a witness came forward and talked about moral hazards.
>
> And I think it sort of really identify itself at that time when we saw there was a decision made that we would take funds out of another one (1) of the Crowns, the insurance Crown, to pay significant monies to the education facilities in Manitoba. And as you'll recall there was very significant push back on that issue from the public.
>
> So I just wanted to highlight that this is an issue, and it will be an issue significantly if the plan that is being put forth, the rate path that Manitoba Hydro has. When you start identifying that you're going to be sitting with billions of dollars in a Crown company that you can expect, especially when the revenue streams of the province are not sufficient in order to

> generate their own -- start their own responsibilities, that there will be likely a push to acquire more funds from those Crowns.
>
> And so when the Board is looking at it, I think you need to identify that is one (1) of the risks going forward. The PUB saw on one (1) hand, too, when the wellness of the Corporation's started to improve, so did their O&M expense [increase][12] dramatically. And, indeed, if you even look at Manitoba Hydro today relative to some other Crowns across Canada that the staffing complement is still high, notwithstanding some of the changes that have occurred most recently. [T6047-6048]

An example of this effect is illustrated by the increases in the debt guarantee fee, which was still very low at the time of Limestone in-service, but increased significantly as Hydro began generating larger net income after the late 1990s, as reproduced below from MIPUG Exhibit 15, page A-13:

Figure A-7: Manitoba Hydro Cost of Debt (Interest Payments & Debt Guarantee Fee) Comparison to MB CPI (cents/kW.h) MH16 w. Interim Update and MH15 Rate Increases – 1994 to 2036[18]



[12] Note transcript correction at page 6318 to 6319

The above figure A-7 highlights that from 1994 (after in-service of Limestone) to 2023 (the full in-service of Keeyask), the inflation adjusted cost of interest to Hydro's external lenders (the blue section) has increased only a small amount, and is back to the same level as after Limestone within about 7 years. The issue today is the black section, which is the debt guarantee fee charged by the Province. This fee began at a low level, but has increased dramatically, and no signs of relief have been projected for Keeyask in-service so as to parallel the low fees originally charged when Limestone came into service.

A final summary of risks and impacts of Hydro's plan was provided by Mr. Osler who noted:

> MR. CAMERON OSLER: … It inserts a rate path needed at four (4) times the expected inflation for six (6) years, ignoring any discussion, really, of impacts on people, ratepayers, the province's economy, the North, et cetera, let alone stability, let alone the issue of predictability in the future. What's going to happen when we achieve this wonderful thing?
>
> Ignores the moral hazards of rate -- for ratepayers who are putting up the money for the equity when the 3.5 billion Mr. Bowman described earlier of new equity has been put in the funds. The ratepayers' children and their children's children do not get to earn money on that equity that they put up. In fact, the concept of what will happen to it is very wide-open. But one (1) thing that you can be sure of, aside from what this Board could do to rates, the government has a lot of -- the government of that day has a lot of openings. [T6050-6051]

ISSUE TOPIC #7:

ISSUE: SUFFICIENCY OF CURRENT RATES TO COVER CURRENT COSTS

Are the rates in place today, and in recent years, covering Hydro's costs?

MIPUG SUMMARY AND/OR RECOMMENDATION:

By all longstanding and accepted financial metrics, rates today more than cover today's costs. Hydro's ongoing operations (excluding major new capital) remains funded 25% by equity, and this has been maintained despite over $1 billion in adverse movements in "unrealized" losses in the last 5 years (arising from temporary movements in such factors as USD:CAD exchange rates). Fully today's rates fully cash finance all operations and interest costs (once major new generation, transmission and DSM is accounted for as long-term assets) as well as 100% cash financing over $500 million of "sustaining" capital including major facility rebuilds that will last decades into the future.

DISCUSSION AND SUPPORT:

Looking to values derived from Hydro's audited financial statements, under cross examination Hydro's Chief Finance and Strategy Officer, Mr. McCallum confirmed that as of March 31, 2017, Hydro's equity stood at $2.816 billion[1]. Mr. McCallum also confirmed that net debt stood at $15.444 billion as of the same date. Each of these values is consistent with the presentation by Hydro in Exhibit MH-135-1. The result of these debt and equity values is a debt ratio of 84.6%.

However, this debt balance includes debt borrowed for major capital projects. Mr. McCallum confirmed that the capitalized amounts for the 5 major capital projects totals $6.862 billion[2]. Absent this balance the net debt would total $8.582 billion[3].

Using $2.816 billion in equity and $8.582 billion in debt, Hydro is, as of March 31, 2017, at a 75% debt ratio absent major capital projects. Note that this is fully in line with financial targets.

Under cross-examination, Mr. McCallum noted that the equity at $2.816 billion includes the adverse effect of $709 million in unrealized losses presently recorded as Accumulated Other Comprehensive Income (or 'AOCI' as an "other comprehensive

[1] Transcript page 7618.
[2] Transcript page 7619-7622 confirmed balance of $3.152 billion for Bipole III, $379 million for Conawapa, $3.276 billion for Keeyask, $30 million for MMTP and $25 million for GNTL, for a total
[3] Transcript page 7622.

loss") primarily related to valuations on Hydro's pension plan and valuation of Hydro's US dollar denominated debt[4]. This is a swing of over a billion dollars to the detriment of the debt ratio in the last 5 years.

In other words, not only has Hydro maintained a 75% debt ratio on all assets other than major new capital, Hydro has managed this while absorbing over $1 billion in adverse valuation movements in accounts that have not even been realized. Note that outside of AOCI, as of March 31, 2012, Hydro had $3.102 billion in equity and since that time has grown retained earnings by $449 million[5], not counting the effects of the Bipole III deferred contributions.

On the matter of net income, Hydro's evidence shows that Hydro continues to record positive net income each year since at least 2007, as shown in the Annual Report provided in Appendix 6.1[6]:

Financial statistics

For the year ended March 31	IFRS		CGAAP							
	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
			dollars are in millions							
Net Income	39	125	152	79	61	150	163	266	346	122
Net income (loss) attributable to:										
Manitoba Hydro	**49**	136	174	92	61	150	164	266	346	122
Non-controlling	**(10)**	(11)	(22)	(13)	-	-	-	-	-	-
	39	125	152	79	61	150	164	266	346	122

Under cross-examination, Dr Yatchew confirmed that positive net income is a sign that rates are covering the costs of operations, depreciation, interest and contributions to reserves:

> MR. ANTOINE HACAULT: … Now, if a Utility were able to keep positive net income each year, including the depreciation expense, wouldn't this not be evidence that each generation of consumers is paying their own costs?

> DR. ADONIS YATCHEW: I would have to think that through. It's not obvious to me that positive net income is a sufficient condition. It might be, but I'm not sure I have a -- I'd have to think about that a little bit more carefully.

---

[4] Per MIPUG/MH-II-4b: "AOCI is comprised of unfunded pension obligations and unrealized foreign exchange losses – both of which are future obligations of the corporation."

[5] Per Exhibit MH-135-1. From March 31, 2012 to March 31, 2017, Hydro grew the retained earnings balance from $2.450 billion to $2.899 billion.

[6] Year ending March 31, 2016 Annual Report, page 112.

> Certainly, it's helpful.
>
> MR. ANTOINE HACAULT: It's helpful in the sense that they'll have paid the operating costs in that year, correct? They'll have paid the depreciation costs based on useful life; correct?
>
> DR. ADONIS YATCHEW: Yes.
>
> MR. ANTOINE HACAULT: So we know also they'll have paid the interest cost on that asset; that's another expense that they'll have paid? All of those key factors will have been paid by the ratepayers if we achieve a net income number, correct?
>
> DR. ADONIS YATCHEW: I would agree with that.
>
> MR. ANTOINE HACAULT: Okay. And if, in addition to paying these numbers, we're asking ratepayers to build up reserves, that is a contribution that we're asking from ratepayers over and above the payment of interest, the payment of depreciation and the payment of operating expenses; correct?
>
> DR. ADONIS YATCHEW: If there is a separate reserve that one is attempting to build, I suppose yes. [T4486-4488]

Hydro has raised concerns that on a "normalized" basis, Hydro has experienced "effectively zero or negative net income"[7]. Hydro's contention for this conclusion primarily relates to the above average water conditions, and to what Hydro calls the "income impact of Bipole III capitalization"[8]. However, neither of these factors indicate that rates are insufficient:

1) In respect of high water, the Board has set rates the last number of years well aware of water conditions, and has allowed Hydro rate increases well above inflation so as to yield positive net income in light of known water conditions. This net income now resides in retained earnings. The financial forecast is modelled assuming mean water conditions, and there is no prospect that ratepayers are banking on continuing high water to fund future net income. Hydro's efforts to "normalize" the net income by ignoring actual experienced high water is inappropriate, particularly as Hydro would presumably not normalize to suggest no rate response is required in low water conditions.

[7] MH-137, page 7.
[8] MH-137, page 8.

2) In respect of Bipole III, this project is not yet in service and the costs of interest is a valid component of costs to capitalize, as is typical utility practice. There is no basis to suggest rates today are inadequate because they do not cover the costs of assets still under construction.

In short, under an accrual accounting approach, consistent with Hydro's IFRS income statement, there is no basis to the assertion that rates have not been keeping up with costs.

On the cash side, Hydro has suggested rates today don't cover costs since they do not permit Hydro to fully cover current costs. Specifically, Hydro noted that it was "borrowing money to fund core, continuing operations"[9]. The testimony of Mr. McCallum became sensational on cross-examination:

> MR. ANTOINE HACAULT: I'm not good at accounting terms, and I always get criticized at this, but I think I heard you say, the deficit. Am I understanding that from a financial perspective, that means that you would have to be borrowing to do things like what we reviewed yesterday, renewing Pine Falls for the next thirty (30), forty (40), fifty (50) years?
>
> MR. JAMES MCCALLUM: We're borrowing to do that. We're borrowing to meet our interest payments. We're borrowing to meet our sustaining capital needs. We're borrowing to meet our payments to the City of Winnipeg. We're borrowing to meet our mitigation obligations. Yes. [T1868-1869]

When this issue was reviewed in detail under cross-examination by Mr. Hacault, Mr. McCallum's claim was shown to be demonstrably false, using the following exhibit (from MIPUG-23-2, page 14):

[9] Exhibit MH-64, page 16

Manitoba Hydro Rebuttal (MH-52) Figure 1.10
Cash Flow (Deficiency)/Surplus (MH16 Update with Interim at MH15 rate increases and 20 year WATM)

($ Millions)	2017/18 Forecast
Receipts from Customers	2,152
Payments to Suppliers and Employees	(892)
Interest Paid	(528)
Bipole III and Other Business Operations Capitalized Interest*	(197)
Business Operations Capital Expenditures	(586)
Demand Side Management	(55)
Mitigation and Other Deferred Expenditures	(27)
Ineligible Overhead	(20)
Cash From Operations Less Capex	**(153)**
Mitigation, Major Development & Other Liability Payments	(59)
City of Winnipeg Payments	(16)
Cash Flow (Deficiency)/Surplus	**(228)**

Interest Paid (Net of All Capitalized Interest) (MH16)	
Gross Interest paid	(768)
Provincial Guarantee Fee paid	(154)
less:Intercompany Interest Receivable	15
less: Capitalized interest (Bipole III and OBO)	
Bipole III (at Weighted-Average Rates)	174
Other Business Operations	22
less: Capitalized Keeyask, MMTP & GNTL	163
Interest Received	5
Timing Difference	16
Interest Paid (Net of All Capitalized Interest)	**(528)**

Bipole III (at Weighted-Average Rates)	(174)
Other Business Operations	(22)
Total	**(197)**

Business Operations Capital Expenditures (586) → Next Page

The above figure was used to highlight that Hydro had $2,152 million in cash receipts in 2017/18, this amount is more than sufficient to fully satisfy all operations cash outflows ($892 million) plus interest paid ongoing operations ($528 million) without issue and with significant surplus left over after those two categories to finance capital spending. The exhibit showed that although Hydro sought to calculate a $228 million cash shortfall in 2017/18, this value only arises under two key assumptions:

1) Bipole III interest of $174 million should have been cash financed (even though this major project is not in service in this year).
2) DSM of $55 million should similarly be cash financed even though it is expressly pursued on the basis that it provides benefits many years into the future, with extremely limited system benefits in the near-term.

Adjusting the table for only these factors ($174 million plus $55 million = $229 million) means Hydro was already cash neutral in 2017/18. Note that adjusting the table in this manner is entirely consistent with Hydro's long established perspectives regarding cash flow targets (the capital coverage target) which exclude major new long-term investments. Mr. Bowman addressed the reason for this, quoting Hydro's previous senior financial staff (Ms. Lyn Wray) describing why major capital should not drive your cash flow targets below a 1.0 ratio, as follows:

> MR. PATRICK BOWMAN: … The reason for that is that obviously, that would drive the target down, and it would be unfair in our view to try to seek rate increases, for example, to get it back to one (1) when, in essence, you're investing in a long-term asset with long-term benefits. [T6188]

More importantly, the table above illustrates that the condition of being in a cash balance arises only when Hydro is financing $586 million of capital reinvestment entirely with cash and no new debt. As illustrated in the cross-examination of Hydro[10], this included the example of the Pine Falls Unit 1-4 Major Overhauls. This project was a renewal of assets put into service in 1951 which are now fully depreciated as part of rates charged in the past. The renewed asset will extend the life for many decades, with the costs recovered in depreciation expense from future ratepayers. In addition the project will increase the capability of the plant by 17%. (see Transcript pages 1787-1791). Many similar projects were included within the $586 million of capital that Hydro now appears to want to cash finance in the year constructed, regardless as to the long-term benefits to ratepayers.

What is particularly troublesome in the current proceeding is that Hydro has a test for cash flow, known as the Capital Coverage test. This test, when measured at a 1.0 level, indicates Hydro's case is fully covering its cash outflows in the year, including normal capital, as described by KPMG:

> The capital coverage ratio is calculated as Cash Flow from Operations divided by Base (or sustaining) Capital Expenditures. Base Capital Expenditures exclude major new generation and transmission projects. The logic of this ratio is that the corporation should be able to fund its sustaining capital from current operations, without accessing external sources of funding.[11]

This target has been a component of Hydro's financial targets since the 1990s, although the desired level has increased in this timeframe from 1.0 to 1.2. Hydro publishes the results of the Capital Coverage metric for each year of each financial forecast, and the MIPUG Scenario from MH-93 (the scenario underlying the 3.57% annual increases) shows that a ratio of 1.0 is exceeded every year and the 1.2 target is in fact exceeded in all but 2 of the next 20 years[12].

---

[10] Transcript 1787-1791.

[11] Appendix 4.1, page 138.

[12] Exhibit MH-93 page 3 to 4.

Hydro appears to express a new concern that this metric is incorrectly structured, in that it purportedly ignores material cash outflows for the City of Winnipeg commitments related to the purchase of Winnipeg Hydro, and some complement of mitigation payments. The fact that such a redefinition is needed now seems particularly curious:

1) The obligation to the City of Winnipeg has existed since the assets of Winnipeg Hydro were purchased in the early 2000s. This includes periods when staff such as Ms. Lyn Wray were present, who were involved in the original development and definition of the targets. Were these items appropriately to be included in the target measurement, it seems unlikely this would have been an oversight until the present day.

2) Appendices 4.1 and 4.2 set out the recent review of financial targets conducted by KPMG (updated in Appendix 4.5) and Hydro's response to the review. As a result of that study, Hydro updated the targets and adopted a new target (EBITDA Interest Coverage) to replace a previous version (EBIT Interest Coverage). Nowhere in those reports is the issue of mitigation payments nor payments to the City of Winnipeg referenced.

Moreover, Hydro discussed the issue of mitigation payments under IFRS in response to PUB-MFR-100, page 7, noting:

> The transition to IFRS has had no impacts on the accounting or dollar thresholds applied to mitigation costs. Mitigation related expenditures continue to be capitalized in the costs of the plant assets for which they pertain and continue to be amortized over the remaining lives of those assets. The dollar thresholds considered for the capitalization of mitigation expenditures can vary depending on the nature of the expenditure/project.[13]

Further, the mitigation payments and City of Winnipeg payments are specifically noted as an "investing activity" akin to capital spending, and not an operating cash outflow, in PUB-MFR-23 page 4. As noted by Mr. Bowman, to the extent these are capital-related costs of investment, or are related to major new generation or transmission, they would not belong in the longstanding capital coverage target:

> MR. PATRICK BOWMAN: … And I think that if Hydro was to go forward to propose a revision to the definitions to that target to include those cash commitments, I don't see why anyone would oppose them if they're actual cash outlays in that year. Assuming that they're meant to be cash outlays

[13] PUB-MFR-100 page 7

> in that year, and they're not in the nature of payments being made to someone for a future development. [T6398]

Regardless, the appropriate way to address these concepts is not to narrowly apply new and ever-changing standards to Hydro's financial metrics, it is to prepare a proper up-to-date assessment of the financial targets, with a full summary of the principles and implications, and bring that forward for PUB review. Pending that, the new mathematics calculated by Hydro reflects a disjointed approach akin to Mr. McCallum's testimony that suggests new financial ratios could be thrown into never-ending debate:

> MR. BOB PETERS: Mr. McCallum, I know you don't wear an accounting designation but is there an accounting standard as to the only way to calculate the debt/equity ratio?

> MR. JAMES MCCALLUM: Subject to check, no, I don't believe so. I think it's -- the debt/equity ratio is not in an IFRS ordained metric. It's a conventional financial analysis which means -- and I've mentioned this to Madam Vice Chair Kapitany a few times that there is a -- financial ratios are a little bit like Baskin-Robbins, there's a lot of flavours. [T7589-7590]

There is a reason a principled rate regulator and a mature utility have ongoing and methodical discourse about things like financial targets over a series of hearings, so that a common understanding and language can be used, proper assessment and comparison can occur, and sensational or flippant claims such as "borrowing to meet interest payments" can be avoided. Hydro's latest claims of cash and rate insufficiency should be viewed through the context of their inconsistency with conclusions drawn from the established and well-founded metrics. Should Hydro wish to again update the financial targets (having just completed an update less than 3 years ago) they should bring those conclusions and recommendations for new targets forward to the Board for a proper and thorough review. Pending confirmation of such targets, all of the new claims regarding CFO:Capex, cash and rate insufficiency, and borrowing money to fund core operations should be viewed with a high degree of scepticism, if not dismissed outright.

ISSUE TOPIC #8:

ISSUE: IS BIPOLE III DRIVING THE NEED FOR THE 7.9% RATE INCREASE

With the imminent in-service of Bipole III, is there a significant rate pressure from Bipole that is at the core of driving the need for 7.9% increase today?

MIPUG SUMMARY AND/OR RECOMMENDATION:

Bipole III will drive an incremental cost impact on Hydro's finances of $241 million less $15 million for avoided line losses. The Bipole III deferred rate increases will yield $181 million, so the resulting total cost impact over 2018/19 and 2019/20 is only 1.4% per year. A further approximately 2% per year will be needed over two years 2022/23 and 2023/24 to transition off of the amortization of the deferred Bipole III balance. In total, Bipole III's cost impacts can be well managed within the traditional rate framework and are not a reason to adjust to a new 7.9% rate increase plan.

DISCUSSION AND SUPPORT:

Mr. Bowman addressed the issue of Bipole III cost impacts in his direct evidence when he noted in regard to the Bipole III deferral:

> MR. PATRICK BOWMAN: … we already have customers paying somewhere between 11 and 12 percent towards the Bipole project even though it's not in service. The first time I heard the idea, I wasn't favourable to it. I think in hindsight it was a very wise move by this Board and it's help phase that in and, as a result, when Bipole comes into service there's very little more impact into rates that's isn't already built in. [T6417]

Mr. Bowman's conclusion was drawn from analysis provided in response to MH/MIPUG-6, and from the Minimum Filing Requirements that Hydro provided to the Board. Specifically, the total annual costs for Bipole III and Riel station are set out at PUB-MFR-20, page 9, excerpted below:

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Finance Expense	14	9	115	217	220	223	219
OM&A Costs	-	-	8	13	13	13	14
Depreciation	9	10	73	107	107	107	107
Amortization of BPIII Reserve	-	-	(47)	(71)	(71)	(71)	(71)
Capital Tax	16	22	25	25	24	24	24
	39	40	175	290	293	296	292

As is shown in the above table, Bipole III total costs once the project is in-service (2019/20) are $361 million, comprised of $217 million for finance expense, $13 million for OM&A, $107 million for depreciation, and $25 million for capital tax.

For the first five years, this cost is offset by amortizing $71 million to the income statement from the Bipole III deferral account, for a net cost of $290 million (also note that the $71 million/year estimate is now low, since it does not include revenues gained from the recent additional 3.36% increase targeted to this account – this amount is now estimated at $80 million/year per Appendix 3.8).

Of this cost, the above table indicates that $40 million is already in rates for 2017/18, and comprises part of what ratepayers have been paying since at least 2016/17. This related in part to portions of the project that are already in service (Riel) and also to the capital tax on the entire project, as that amount is not capitalized to the project but rather included in current day costs even though the project is not yet 'used and useful'. Note that despite this $40 million value being Hydro's number provided to the PUB in the Minimum Filing Requirement document, Hydro has oddly sought to portray this value as an "erroneous assumption" by Mr. Bowman[1].

The evidence from PUB MFR-20 is that costs for Bipole III as at 2019/20 is an annual cost of $361 million by 2019/20 (2 years out) which will be offset by $80 million from amortizing the Bipole III deferral account, for a net cost of $281 million. This compares to the costs already in rates at 2017/18 of $40 million, for a net impact to costs over the 2 years of $241 million.

The major offset to this is the amounts already included in rates from the Bipole III deferral account. At present, this totals 11.12% of total rates for all domestic revenue. Based on the rates in place today (per Appendix 9.1 Updated, page 1) of $1.630 billion, this rider yields $181 million on an annualized basis. The remaining unfunded portion of Bipole III costs therefore totals $60 million.

[1] Manitoba Hydro rebuttal evidence, Exhibit MH-52, page 30.

Finally, as has been reviewed in the evidence (e.g., MH/MIPUG-6), there is a $15 million/year cost savings (offset) as a result of Bipole III from reduced line losses.

Over the 2 years that Bipole III comes into full service, there is a need for a further $45 million in rate increases. As a percentage of existing rates ($1.630 billion), this is an impact of only 2.8%, which if spread over 2 years results in a 1.4% rate increase in 2018/19 and a further 1.4% in 2019/20.

This is of course not the full Bipole III impact, as the $80 million amortization will end spread over 2 years 2022/23 and 2023/24. At that time, further increases will be required of an average $40 million per year. Given revenue growth between now and 2022/23, this remains at approximately 2% per year.

Given the Bipole III account and the amounts in rates today, the total increases justified by Bipole III are as follows:

- 1.4% in each of 2018/19 and 2019/20
- Approximately 2% in each of 2022/23 and 2023/24.

Further, this is the total rate impact needed to fully incorporate Bipole III costs into rates as at the date the cost effect arises. As Hydro's largest capital project ever undertaken (pending Keeyask coming into service), it would not be unexpected that Bipole III would take at minimum a few years to achieve the level of full cost recovery. In this case, however, reflecting the benefits of the Bipole III deferral account, the net impact can be absorbed without rate shocks and without major transition provisions being required.

A question that can be raised is whether a similar deferral account concept is appropriate for Keeyask costs (i.e., starting with a new rate deferral account in the near-term before Keeyask is in service). This is not advised given Bipole III and Keeyask are materially different types of assets, reflecting two key reasons:

1) Bipole III is being put in-service primarily to address reliability concerns regarding Hydro's existing system. This means that it is in effect fully used and useful, and providing the key benefits intended, in the period from when it comes into service. Keeyask, on the other hand, is a generating station with a long-term economic profile of bringing new revenues. Keeyask was originally advanced to 2019 based on an express concept articulated in the NFAT review that it would not fully cover its own costs at the time it comes into service (and is not fully used and useful by ratepayers immediately to meet domestic load requirements), but would be preferred over the long-term based on discounted costs and Net Present Value analysis. For this reason, it can be appropriate to think of Bipole III rate impacts from the day it comes into service, while Keeyask rate impacts should be considered over a much longer time frame.

2) Keeyask brings with it revenues, which are intended to grow with time. Bipole III does not bring with it new revenues (at most Bipole III brings a small degree of avoided line loss benefits).

For this reason, it is appropriate to think about the Keeyask transition being undertaken following Keeyask is in-service, over the first one to two decades of its life, as opposed to Bipole III which had the transition underway to reflect full cost recovery very soon after it came into service.

ISSUE TOPIC #9:

ISSUE: REGULATORY DEFERRAL ACCOUNTS

Has Hydro appropriately reflected the Board's directives and reasonable regulatory standings in the regulatory deferral account projections in MH16 Update with Interim?

MIPUG SUMMARY AND/OR RECOMMENDATION:

Hydro has not reflected the Board's previous directions, nor reasonable regulatory standards, in its forecasting of the deferred overhead and depreciation methodology accounts.

MIPUG's recommendations in respect of deferred overhead is that these amounts are, for all intents and purposes, capital costs and should be recognized as such. MIPUG recommends that the deferred ineligible overhead account should be amortized over 30 years (approximately equal to the average age of Hydro's overall asset base) and continue this accounting procedure in perpetuity (instead of Hydro's proposed deferral period until 2022/23). This treatment will mimic the continued capitalization of these overheads as the PUB directed in Order 73/15.

For the change in depreciation method account (Equal Life Group/Average Service Life) Hydro should assume indefinite use of ASL (instead of Hydro's proposed deferral to 2022/23) for the purposes of the IFF. An issue arises for Hydro internal accounting if Hydro remains fixated on using ELG for financial reporting purposes, as Hydro will be recording different depreciation expense in each year for regulatory versus accounting purposes. By taking this action, Hydro creates a hypothetical "deferral". This is not the issue for the PUB, but rather an issue between Hydro and its auditor.

Nonetheless, to the extent addressed by the PUB, it should be explicitly noted that this "deferral" account should not be actively amortized through rates, as doing such would explicitly undermine the PUB's determination to use ASL-linked costs. Further, as the very principle is that the ASL and ELG methods will match over time (as under both methods assets are fully amortized upon retirement), and as such any difference will naturally amortize and balance over time, no such amortization of the deferral is required.

If needed, this can be revisited if and when Hydro complies with Board Order 73/15 regarding review of an "IFRS-compliant ASL study". It should not be assumed that ELG will be adopted in a future period by the PUB.

MIPUG takes no issue with Hydro's proposed treatment for the remaining deferral accounts (Conawapa, Bipole III deferral and treatment of gains and losses on the disposition of assets) at this time.

DISCUSSION AND SUPPORT:

Manitoba Hydro is seeking PUB endorsement of the following, pertaining to various deferral accounts:

- The proposed deferral and subsequent amortization for the costs incurred with respect to the Conawapa Generating Station as discussed in Tab 3 (page 18) of this Application;
- The proposed amortization period for the disposition of the regulatory deferral account established to capture the annual difference ($20 million) between overhead costs expensed for financial reporting purposes based on IFRS and overhead costs expensed for rate setting purposes reflecting Order PUB 73/15;
- The proposed amortization period for the disposition of the regulatory deferral account established to defer gains and losses on the disposal of assets; and
- The proposed time frame for the recognition into revenue of the Bipole III deferral account.
- With respect to the depreciation method deferral account, Hydro's preference is to have a single basis of depreciation for both reporting and financial purposes but respects that the PUB's directive from Order 43/13 must first be addressed.[1]

MIPUG takes no issue with the Bipole III deferral, the Conawapa deferral, or the deferral of gains and losses on disposal. MIPUG does take issue with the proposed treatment of the O&M capitalized overhead and Depreciation Methodology accounts, in that the treatment goes against previous PUB directives in PUB Order 73/15 (e.g., Directive 10 of this Order).

The Board has previously noted that these ineligible overhead and depreciation amounts should be deferred indefinitely, and either amortized to income over an average life of assets[2], or not amortized through income but rather matched over time as a sort of "unrealized" imbalance akin to Accumulated Other Comprehensive Income (AOCI)[3]. Note that this latter approach (the approach to not amortize the difference to income) was in fact the very scenario used by the Board in Attachment 46 (Scenario 2) to the 2016/17 Interim Rates Review used to set the 3.36% rate increase actually awarded.

[1] MH-137, page 212

[2] Attachment 28 from the 2015 Interim Rates Review.

[3] Attachment 46 from the 2015 Interim Rates Review.

Further note that the Board again endorsed this view of "no amortization", at least with respect to depreciation, in its letter to Hydro of April 4, 2016, which was included in Appendix 10.9 of the current application, noting as follows:

> At the outset, the Board clarifies that its mandate with respect to prescribing accounting methods is limited to determining the appropriate accounting for rate-setting purposes, but not for financial reporting purposes. While in the Board's view, it would be preferable for Manitoba Hydro's financial statements to be consistent with the Board-approved rate-setting methodology, the Board cannot provide the requested guidance as to how Manitoba Hydro should prepare its financial statements for financial reporting purposes. As such, both Manitoba Hydro and Centra should seek the appropriate guidance from their internal and external accounting advisors with respect to their options and obligations under IFRS to comply with the directives of Board Order 73/15. This should include a consideration of whether there is any risk of the utility having to re-state its financial statements in the future if the financial reporting methodology does not align with the Board-approved rate-setting methodology.

> With respect to accounting adjustments used in the preparation of financial forecasts for rate setting purposes, the Board does not understand Manitoba Hydro's proposed accounting treatment to be consistent with the Board's intent in Order 73/15. For rate-setting purposes, the Board considers Attachment 46 Scenario 2 filed by Manitoba Hydro in its recent application for interim April 1, 2016 rates to be consistent with intent of Order 73/15.

Note that although the Board was clear that Attachment 28 and 46 from the 2015 Interim Rates review were consistent with the Board's findings, in this GRA Hydro has applied methods and approaches inconsistent with those findings, as shown below (per MIPUG-MFR-5, pg. 1):

> The table below compares the accounting treatment reflecting Order 73/15 in MH16 and Attachment 28 from the 2016/17 Supplemental Filing:

	MH16	ATTACHMENT 28
INELIGIBLE OVERHEAD		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	30 years
Ineligible Overhead Deferred Until	2022/23	Indefinite
EQUAL LIFE GROUP (ELG)/AVERAGE SERVICE LIFE (ASL)		
ELG/ASL Amortization Period	20 years	34 years (2.98%)
ELG/ASL Deferred Until	2022/23	Indefinite

Manitoba Hydro's concerns with respect to the adjustments in the table above are stated in response to PUB/MH I-1b:

1. Substantial growth in regulatory deferral accounts results in intergenerational inequity and poses a risk to rate stability for future ratepayers in the event of the occurrence of adverse risks such as drought and/or higher interest rates.
2. Although changes in amortization periods can result in improvements to net income and retained earnings, such changes do not result in an improvement in the corporation's cash position, which is key to sustaining and improving the financial strength of Manitoba Hydro.

Hydro now appears to suggest, per Final Argument, that it is concerned insufficient information is on the record regarding these "technical" topics and indicated that Hydro is supportive of an alternate process where the issue of indefinite deferral of ineligible overhead and depreciation can be addressed.[4] MIPUG is not averse to reviewing issues at a technical process, so long as the past Board directives (which were arrived after extensive and expensive reviews) are respected.

With respect to depreciation, until Hydro complies with previous Board directives in Order 143/13 and 73/15, the presumption of reverting to ELG methodology in 2022/23 is inappropriate and MIPUG recommends that the PUB not accept financial scenarios that make this assumption. This is consistent with MIPUG's previous position when this topic was reviewed fully, as outlined in Order 73/15 (pages 42 – 43):

> MIPUG submitted that ASL is appropriate for rate setting and is used by the vast majority of North American utilities, particularly Canadian Crown utilities and hydro-based operations.
>
> MIPUG submitted that the use of ASL benefits the intergenerational perspective and that a Crown-owned, hydro-electric utility, such as Manitoba Hydro, should take a consistent and properly matched long term approach to collection of depreciation which matches the use and usefulness of assets. This is done by using ASL, which charges the same depreciation rate in each year of the asset's life.
>
> MIPUG further submitted that ELG is not a more precise method of depreciation as the claims of ELG precision are linked to a theoretical construct of ELG that is not used in practice, where the theoretical purity of the method is significantly diluted.

At this time, without compliance to PUB directives in this matter and without proper process to review these directive responses, Hydro's depreciation methodology in the

[4] MH-137, page 212 & 213

financial forecast should comply with PUB directive, as reflected in the below, without amortization of the difference (which will net out naturally over time).

IFF16 Revenue Requirement Impacts from Hydro's Proposed Depreciation Method Deferral Account (MIPUG-26, slide 40)

Regulatory Deferral - Change in Depreciation Method ($ Millions)	Actual 2015	Actual 2016	Actual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1 Opening Balance	-	28	59	91	125	164	201	236	272	315	298	281	263
2 Additions	-28	-31	-31	-34	-40	-43	-45	-48	-56	0	0	0	0
3 Amortization	0	0	0	0	0	6	9	12	14	16	18	18	18
4 Closing Balance	28	59	91	125	164	201	236	272	315	298	281	263	245
5 Net Movement	-28	-31	-31	-34	-40	-36	-35	-36	-42	16	18	18	18
6 IFF16 Depreciation Expense (i.e. ELG)	352	367	375	396	471	515	555	597	689	714	726	739	752
7 Depreciation IFF16 & Net Movement	**324**	**336**	**344**	**362**	**431**	**479**	**520**	**561**	**647**	**730**	**744**	**757**	**770**
*8 Derived 'ASL' Depreciation Expense***	*324*	*336*	*344*	*362*	*431*	*472*	*510*	*549*	*633*	*655*	*666*	*678*	*691*

Total excess depreciation over first 10 years - $352M.
By 2027, totals $80M/year (carries into 2028-2037 period).

ASL outcome

Higher than ASL (due to amortizing)

Much higher than ASL – higher than ELG (due to amortizing plus use of ELG)

With regard to Hydro's intergenerational inequity concerns, Mr. Bowman commented with respect to both accounts that the use of these accounts, and the PUB's directives in these matters, is appropriate for rate setting. These deferred expenses are in line with regulatory principles and should be reflected in the financial forecast used for rate setting. As explained by Mr. Harper the use of regulatory accounts is common practice for regulated utilities:

> MR. WILLIAM HARPER: … I'd like to now turn to the second issue addressed in my evidence, which is the regulatory accounts. First off, it should be noted that the use of regulatory accounts is a common practice by regulated utilities, and it serves a number of useful purposes. These purposes include promoting intergenerational equity by allowing costs to be deferred and amortized so as to better match the timing of when the costs will be paid by customers and when benefits will be received by customers. They also address forecast uncertainty such as neither the Utility, nor customers are unfairly burdened with the associated risk. They're used to smooth rate increases. They're used to permit the recovery and refund of costs and revenues arising from unforeseen events. And finally, they're often used to offset accounting provisions.
>
> However, as the footnote point -- on the slide points out, some of these purposes are more applicable to utilities under rate of return regulation or

> incentive regulation than they are to Manitoba Hydro with its cost of service regulation. And more in specifically that would apply to the issues around addressing forecast uncertainty and the recovery of unforeseen events. [T5213-5214]

Note that Mr. Harper's direct examination slide comparing the balances in the accounts is reproduced below (Exhibit CC-46, slide 22):

Utility	Net RA ($M)	Total Assets ($M)	RA/ Total
BCH (2017)	5,597	31,888	17.6%
HQ (2016)	3,979	75,167	5.3%
OPG (2016)	5,455	44,372	12.5%
Nalcor	-184	14,062	-1.3%
MH (2017)	489	22,338	2.2%
MH (2035 Att 28)	1,888	35,560	5.3%

Further, it should be noted that Manitoba Hydro's deferrals are not simply a smoothing of costs that would otherwise cause rate shock (such as when utilities defer fuel costs), but rather a deferral of capital related costs that actually relate to service provided by those capital assets in the future, as noted by Mr. Bowman:

> MR. PATRICK BOWMAN: … Hydro moved large amounts, $120 million worth of things it used to capitalize into wanting to expense, which put a huge burden on rates as that was done. The Board said no to the last 20 million, and said, I want it capitalized again. These are, in my submission, validly capital costs. They should be treated like capital costs. They should be thought of as capital costs. They're not pushing liabilities off to future ratepayers. They're not ignoring our grandchildren. They are costs that are a true and proper part of Keeyask or Bipole, just as any wire, or turbine, or anything of the sort is, and they ought to be con -- thought about the same way.
>
> In doing that, they should be amortized, much like assets are amortized, because they relate to a pool of assets. If Hydro does not want to track

> them by asset, it can track it as a pool and amortize it, and the suggestion is it should do something like a thirty (30) year horizon, which is the average for all of its assets. It's actually a little higher. And it should to continue to do that in perpetuity. There's no reason not to. It's part of a regulatory standard, and the normal way that a -- any number of these utilities would talk about a regulated is by a set of regulatory accounts and standards that do not always mimic the same as their IFRS accounts and standards. And I think this a good example.
>
> IFF16 -- MH-16 -- MH-16 update with interim include this deferral and amortization, but only for a limited period. So all of the back end of MH-16 has the extra $20 million in costs rather than being deferred and amortized. [T6091-6093]

Mr. Harper’s expert opinion is in agreement with respect to the treatment of ineligible overheads, explaining the rationale for the Board’s decision in this manner, for the purposes of rate smoothing, intergenerational equity or a combination of the two as appropriate.

> MR. WILLIAM HARPER: … In the case of ineligible overheads, Order 73/'15 directed the deferral of these costs. It is not immediately clear from the Board's Order whether this was based on considerations or rate smoothing, intergenerational equity, or a combination of the two (2).
>
> In any event, subsequent communication from the Board directed that the deferred costs be amortized over thirty (30) years, and it's charged through other comprehensive income. In contrast, Manitoba Hydro is proposing to amortize the costs over twenty (20) years and charge them through net income. Manitoba Hydro is also proposing to cease the deferral of these costs after 20 -- 2022/'23.
>
> In my view, Manitoba Hydro's proposal to amortize the deferred costs by net income is reasonable, as this mirrors what would have occurred if these costs were capitalized and subsequently depreciated. However, if the costs were capitalized, they would have been amortized over the lives of the various future assets as they came into service, and on average, these lives are considerably longer than twenty (20) years, or even the thirty (30) years directed by the Board. This would suggest that the thirty (30) year amortization directed by the Board is more reasonable, and indeed, the Board may want to consider even a somewhat longer period.

> In addition, the communication from the PUB makes no reference to ceasing the deferral of these costs. And indeed, if the Board's view is that for rate-setting purposes, the level overhead to be capitalized should include this 20 million, there is no reason to cease the deferral after 2022/'23. [T5216-5217]

With respect to the depreciation approach, the following excerpts are noted:

> MR. PATRICK BOWMAN: … the Board has made its conclusions that Hydro is to use the average service life procedure until such time as it comes back and convinces the Board to do otherwise, and the Board set out clearly what type of studies it would be looking for to do that. I suggest that the Board continue with the average service life, and that it not make an assumption that by default there will be a change to the equal life group procedure.
>
> In the meantime, the thing -- the very simple point that the Board needs to understand is that both methods of depreciation will amortize your assets by the -- over the life of the asset. You will always recover all of your costs. There's a difference in the timing.
>
> And in simple terms the equal life group method puts more of your depreciation costs in the early years of the asset, which is not only problematic from a regulatory perspective; part of the reason it's not approved in a lot of places, but it's especially problematic when you're bringing on huge projects like Bipole and Keeyask.
>
> …
>
> The principle that we're trying to achieve is that the outcome to rates should be the same as an ASL profile. If Hydro wants to do something else, or it elects with its auditors or with its internal accounts to do something else in its own books, it simply needs to provide a true up to be able -- to this Board to be able to implement the decision this Board made, which is to use the average service life procedure. It's not uncommon.
>
> Anything else that's recorded in Hydro's books becomes a difference. And on their books they may have a difference, the part that we've depreciated that we haven't yet recovered from ratepayers. But this Board, by endorsing to this point the ASL procedure, has said, You will recover it from ratepayers appropriately with an ASL methodologies,

> meaning as time goes on when this ELG approach should get cheaper for any given asset.
>
> And that's the cost profile that we should assume we're trying to achieve. In other words, as long as this stuff is tracked by a vintage, by an asset class, it should be naturally amortizing. In the early years it will build up a balance. In the later years it will pay it down. And I provide an IR response where it shows in Hydro's materials that that is exactly what should happen.
>
> Hydro suggested it will be ever-growing, and I think that only arises if someone puts it is a one (1) line item, and bundles this stuff together. It is only ever-growing the same way as your capital plant in service is ever-growing. Any given capital asset is being amortized down, but you're always adding new stuff, so it's ever-growing. But that's not a reason to reject the approach. [T6093-6095, emphasis added]

Mr. Harper, in his direct testimony also explained this regulatory account:

> MR. WILLIAM HARPER: … In the -- if we move back up to the depreciation differences, the PUB also directed in the same Order 73/'15 that Manitoba Hydro continue to use the current average service life, or ASL, depreciation method for rate-setting purposes until the Company had provided more information regarding IFRS-compliant ASL depreciation rates, and also provided information on the impact on its integrated financial forecast of using ASL-based depreciation rates versus the Equal Life or ELG-based depreciation rates.
>
> The need for the regulatory account arises from the fact that Manitoba Hydro uses the Equal Life Group for -- methodology for financial reporting, but per the Board's direction, uses the average service life for regulatory purposes.
>
> Following Order 73/'15, the Board directed that these deferred costs also be amortized over thirty (30) years and charged through other comprehensive income. In contrast, Manitoba Hydro is proposing to amortize the cost over twenty (20) years and charge them through net -- net income. Manitoba Hydro is also proposing to cease the deferral of these costs after 2022/'23.
>
> As I noted in my evidence, both depreciation methods will fully recover the cost over the life of the assets. As a result, from a benefit-matching perspective, there is no need to amortize the balance in the account.

> However, if one was to choose to amortize the balance in the account, a period that would be most appropriate would be one that matched the remaining service life of the existing assets, which is roughly thirty-four (34) years. So in this case, the thirty (30) years directed by the Board would be much more appropriate than the twenty (20) years Manitoba Hydro has proposed.
>
> The Board's directive also called for Manitoba Hydro to return with the necessary information to permit it to make a determination as to which depreciation -- while -- methodology should be used for rate setting. Assuming Manitoba Hydro intends to comply with the directive in a timely fashion, there is no need, in my view, to either, 1) amortize the current balance, or establish a date after which the cost differences between the two (2) will no longer be deferred. These matters can better be addressed by the Board after it has determined what is the appropriate depreciation methodology for rate setting purposes. [T5218-5220]

MIPUG is in agreement with Mr. Harper that 1) amortization for this account is unnecessary as both methods will fully recover the cost over the life of the asset, 2) if the Board does rule in favour of amortization, the remaining service life for existing assets, roughly 34 years, is more appropriate than Hydro's proposed 20 years. In MIPUG's view, the matter of the cost profile for rate-setting purposes for depreciation expense is settled – it should be based on ASL.

Of course the door is open for Hydro to respond to the option provided in Order 43/13 to file a new IFRS oriented ASL study with further componentization[5], and if Hydro undertakes that route, the Board and parties can review such filing. Until such time, this matter has been properly assessed and concluded, and the Board's current ruling to maintain a cost profile consistent with ASL should be used for all financial forecast years (not just until Hydro's proposed 2022/23 timeframe), and with no extra costs to "amortize" the difference between ASL and ELG.

[5] Board Order 43/13, page 5

ISSUE TOPIC #10:

ISSUE: SUSTAINING CAPITAL ('BUSINESS OPERATIONS CAPITAL')

Does Hydro's financial forecast in MH16 Update with Interim reflect optimized sustaining capital expenditures, and should the Board assume there are alternatives to reduce this capital in a manner that would help strengthen Hydro's finances and reduce the degree of rate pressure?

MIPUG SUMMARY AND/OR RECOMMENDATION:

Hydro has not provided any pacing and prioritization alternatives in this rate application for non-critical capital spending, in an effort to mitigate financial pressures or reduce borrowing requirements in the short-term. This option was highlighted by both Boston Consulting Group to Hydro's Board as one area where cost reductions were available, and by the PUB during the last General Rate Application.

MIPUG notes that sustaining capital spending is an area where significant spending is occurring in the short-term, and this is an area where cost reductions have been highlighted as possibilities.

Hydro has proven that it is capable of cost reduction in this area, with, for example, the Gillam Redevelopment and Expansion Project (which was cut by $141 million, a portion of which is not yet reflected in Hydro's financial forecasts). It should be made a priority within Manitoba Hydro to further expand this type of prioritization effort.

DISCUSSION AND SUPPORT:

Manitoba Hydro's sustaining capital expenditures in this financial forecast do not appear to have benefitted from any prioritization or pacing as compared to capital spending levels noted at the previous GRA. In particular, CEF16 is almost identical to spending levels forecast in CEF14 ($5.5 billion compared to $5.6 billion for 10 year forecast).

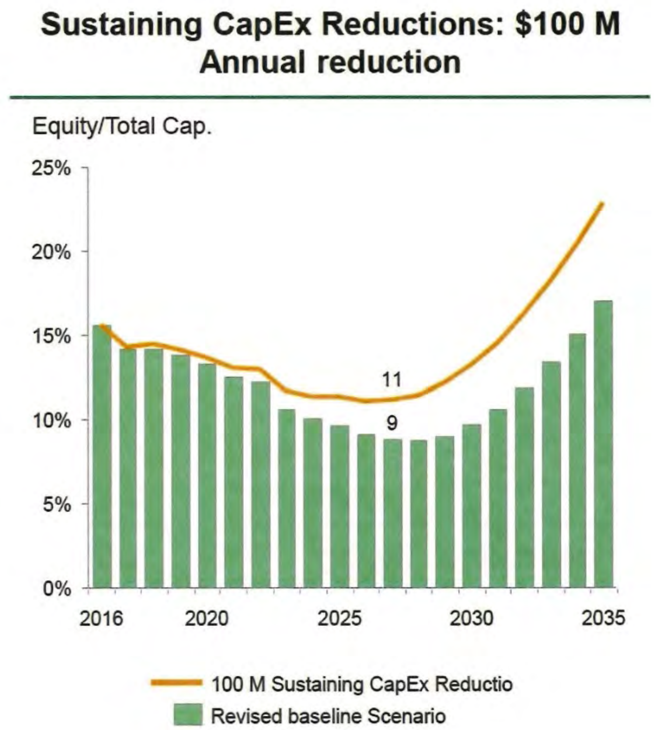
At the last GRA, Hydro's financial plans included increasing sustaining capital spending by about $100 million annually compared to previous levels and forecasts (from spending $470 million in 2013/14 to increasing to approximately $571 million in 2014/15 and $571 million in 2015/16). The 10 year capital forecast in IFF14 included $5.6 billion in capital spending over this period (Order 73/15, page 62). The Board determined in Order 73/15:

> The Board accepts that Manitoba Hydro is faced with aging infrastructure and there may be a genuine need to expand sustaining capital expenditures. As such, for the 2014/15 and 2015/16 fiscal years, the Board accepts Manitoba Hydro's increased sustaining capital spending. However, the Board is not satisfied that Manitoba Hydro has adequately evaluated the long term pacing and prioritization requirements. The Board considers that top-down caps or placeholders are insufficient to justify increased spending in the future. As such, the Board's acceptance of the increased sustaining capital spending during this GRA should not be construed as an endorsement of Manitoba Hydro's long term sustaining capital plan. (pg. 68)

Even before the new financial interpretation that a doubling of rate increases from 3.95% to 7.9% is required, Manitoba Hydro had the incentive and opportunity to look at pacing of sustaining capital expenditures to levels more in line with CEF13 (i.e. reducing by $100 million in the short-term) as a way to control costs and borrowings. However, Hydro's planning sustaining capital expenditures in CEF16 are almost exactly the same as the last GRA (CEF14) at $5.5 billion for the 10 year period (Appendix 3.1, CEF16, page 55).

Manitoba Hydro's position is that "all test year Business Operations Capital investments are required for sustainable, safe and reliable operations to the benefit of Manitoba Hydro's customers which Manitoba Hydro serves by striking a reasonable balance of cost, performance and risk". (MH-137, page 127).

The Boston Consulting Group (BCG) review, highlighted the benefits to the equity ratio of reduced sustaining capital in PUB-MFR-72. The description, at page 133 of 615, was to defer low value capital projects for 5 years. This was described as "Realistic 5-year change". The impact was depicted at page 140 of 615, using the example of a $100 million per year reductions (approximately equal to the $100 million per year increase seen between CEF13 to CEF 14), which shows a sustained benefit through the 2035 period (i.e., the deferral was not depicted as a temporary change):



BCG identified sustaining capital reductions as one of the priorities in strengthening the core business to mitigate the impact of continuing with major capital projects (PUB-MFR-72 page 133 of 615):

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

Manitoba Hydro 2017/18 & 2018/19 General Rate Application
PUB MFR 72 - Attachment
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Updated

4 Summary: What can been done to mitigate impact of continuing?

Highly preliminary values for directional purposes only ($100M retained earnings = ~30-40 bps equity)

	Potential Levers	Base Value:	Realistic 5-year change	Impact on retained earnings
4a Improve the projects	Implement LCPM (schedule review, lean design, construction productivity)	-	Reduce $1.4-1.6B expected overrun across two projects	Not yet quantified
	[redacted]	[redacted]	[redacted]	[redacted] 3a 4a
4b Strengthen the core business	Launch OM&A efficiency program	$542 M	Hold nominal flat for 5 years (~10% cumulative real reduction)	$ 150 M
	Optimize debt maturity to reduce Finance Exp.	$571 M	Reduce average maturity profile of debt from 20 years to 12 years	$ 150 M
	Defer low value capital projects	$577 M	$100 M annual reduction	$ 100 M
4c Grow equity base	"Negotiate" for higher rates (R&SB and industrial)	3.95% annual	5% annual increases on average across the board	$ 300 M
	Revise structure of provincial payments	$317 M	Deferral of capital taxes, and guarantee fees linked to Keeyask and Bipole III until in-service date	$ 200 M
	Structure equity transfer	$0 M	$ 500M one-time payment upfront	$ 600 M

In addition, Province needs to address systemic decision governance: Objective functions, rate regime, investment plan approval process

Heartbeat_Appendix_V1.pptx THE BOSTON CONSULTING GROUP Draft—for discussion only 90

With regard to Hydro's claims that no alternatives are available, MIPUG counsel conducted cross-examination to illustrate one example of how these claims from Hydro are misleading or inaccurate. The focus of that cross-examination was the Gillam Redevelopment & Expansion Project (GREP). This project, listed as a Major New Generation & Transmission Project, has 10 year forecast capital spending from 2018 – 2027 of $226 million (with 20 year total of $241 million) and a total project cost of $266.5 million (Appendix 3.1, CEF16, page 51).

This project is a good example of how sustaining capital clearly can be managed during this time of major capital development, and of how Hydro's rote claims of "no alternatives" do not bear out under scrutiny. This project consists of non-core infrastructure spending and town redevelopment which would otherwise be a municipality responsibility. The infrastructure built and funded by Manitoba Hydro is often subsequently turned over to the Town for ownership, operation and maintenance (Coalition-MH-I-174 Attachment A, page 295). GREP justification is explained as:

> The upcoming northern construction of Keewatinoow Converter Station/Bipole III, Keeyask Generating Station and Conawapa Generating Station is similar to that of the 1960's when MH constructed Radisson Converter Station/Bipole I and Kettle Generating Station, and will require

> similar capital investment to ensure that the Town of Gillam can support Manitoba Hydro's system expansion. A key difference is the need to rehabilitate the aging 1960's era infrastructure while at the same time construct new. (PUB-MFR-115 pg. 267)

In the risk analysis done for the Capital Project Justification, competing capital projects are noted as potentially putting a strain on internal resource availability, and that work within the GREP is non-core business to Manitoba Hydro. Further explained in cross-examination:

> MR. ANTOINE HACAULT: So although Manitoba Hydro is spending this money, it's not going to own the assets?
>
> MR. LORNE MIDFORD: That's correct.
>
> MR. ANTOINE HACAULT: Would you -- and if you can't that's okay. Would you be able to quickly explain whether or not, as a result of giving those assets to the local government district of Gillam, how does the accounting work for that? I mean, is it a Manitoba Hydro asset and you've got no idea?
>
> MR. LORNE MIDFORD: You know, I -- what I -- well, maybe what I can share is why because you're probably you be wondering that. There is a long-standing agreement with the town of Gillam that Manitoba Hydro, in lieu of taxes that we would that folks would normally pay through property taxes -- so in lieu of taxes we provide the costs for -- to the town. And there's also a requirement for any significant major upgrade capital investment. There is also that requirement for Manitoba Hydro to provide that. [T5941-5942, emphasis added]

The GREP project is split into phases. Originally Phase IA had a capital budget of $26.3 million (Coalition-MH-I-174 Attachment 1, page 294), with the remaining phases (IB, 2 and 3) having a much more significant budget which originally started at $366.5 million for the period 2014/15 to 2026/27 (PUB-MFR-115 pg. 264 - 273). Note that at the time of the $366.5 million cost estimate, the Capital Project Justification specifically noted that "No other alternatives were considered as the work must be completed"[1]. This budget was subsequently revised down to $266.5 million (a reduction of $100 million) with a further note that "No other alternatives were considered as the work must be completed"[2]. Hydro has since testified that the project has again been revised down $225 million as noted in the below transcript (a further reduction of $41 million), but this

[1] PUB MFR-115 Attachments page 268.

[2] PUB MFR-115 Attachments page 277.

new lower budget is not included in MH16 Update with Interim. It is not clear how the budget can be revised downwards twice, totalling $141 million, but this option is not in some way an “alternative” that should be highlighted when seeking approval for spending. The details of this project were addressed as follows:

> MR. LORNE MIDFORD: Perhaps I can start by giving the Board some perspective on what this project is. Manitoba Hydro, because we have a significant number of resources in the north near Gillam, Fox Lake traditional territory, and so we have three (3) major plants: Kettle, Long Spruce, and Limestone, as well as two (2) major converter stations and we're building the Keewatinohk converter station as well, and ultimately Keeyask, all to be serviced in the area.
>
> So Manitoba Hydro has a fairly large presence in the area, and those that have been able to travel to Gillam, I know you've seen that. So we have about two hundred and sixty-five (265) employees in the that area. We have -- because of that there's a large amount of residential dwellings that we own to provide accommodations for staff who work and support our facilities in the north from there.
>
> So the generate -- the Gillam redevelopment expansion program, I believe, was initially put in place in anticipation of further expansion requirements to meet the -- to meet this additional infrastructure that was being invested in the north.
>
> We've been able on -- to reduce the need for additional infrastructure significantly. In fact, we are not building any new infrastructure to meet additional resourcing requirements for two (2) reasons. One (1), we've invested in technologies that allows us to remotely operate our generating stations from our system control centre in Winnipeg, which allows us to not staff the plant twenty-four (24) hours a day. And so we've been able to achieve reduction in staffing levels from that.
>
> And also through our corporate staffing reduction plan, and I'm sure you've heard of -- about that earlier. We've been able to reduce staffing levels, so the net -- there will be no net increase requirement to invest and expand the facilities in Gillam. So the Gillam -- the dollar values that are being spent is really just addressing end-of-life infrastructure investments, such as waste and water plants that are end-of-life, water lines that need to be replaced. Just the mass -- it's three hundred and sixty-five (365) homes. The ongoing requirement to upgrade and replace those facilities. So that's what that is earmarked for.

> Now, in terms of what's been spent, I can tell you that the numbers have been reduced from the two sixty-six (266) that you referred to, Mr. Hacault. It's been reduced to $225 million. And the reference to the different phases is really from an old perspective of expansion requirements. What we've done is we've integrated the spend of all these different infrastructure projects like waste and water, and added that to our review process internally to look and justify each based on its own merit going forward. [T5935-5937]

In cross-examination, Hydro provided more explanation on this project and the approach taken to lower the budget to $225 million (tr. page 5940):

> MR. ANTOINE HACAULT: We see that in a revision -- and I think you were involved in this revision, Mr. Midford -- there was some $7.75 million taken out of each year, as in these placeholders?
>
> MR. LORNE MIDFORD: Yes.
>
> MR. ANTOINE HACAULT: For a total of 100 million?
>
> MR. LORNE MIDFORD: Right.
>
> MR. ANTOINE HACAULT: Prior to doing that, was there any discussion with any of the vice presidents of the various business sectors, either generation, transmission or distribution?
>
> MR. LORNE MIDFORD: There was a decision to reduce the overall budget because we didn't think it was a realistic representation of what needed to be spent in Gillam. And so that was together with the vice president of transmission and the vice president of HR and the services.
>
> MR. ANTOINE HACAULT: Okay. And with the couple minutes that I've got left I'd like to take you to -- yeah, at the very top of the slide before I move to another slide, am I right in understanding this capital justification project to indicate that no other alternatives were considered indicating the work must be completed?
>
> MR. LORNE MIDFORD: We did to consider -- tried to think of alternatives to this. In the end, we have a lot of infrastructure that supports our operations through our staffing requirements, and those -- that -- those assets are coming to end-of-life. Just like in your house, you have to replace a roof every, you know, twenty (20) years. Multiply that by three hundred and sixty-five (365). So it's in terms of an asset management and

spend requirement there's definitely a need to ensure that we have adequate facilities for our staff to support our assets.

MR. ANTOINE HACAULT: But to be clear, these are just placeholders. If you had done a detailed analysis you wouldn't do a blanket cross off of $7.75 million each year without knowing exactly what you're going to cut.

Isn't that correct, they're just placeholders?

MR. LORNE MIDFORD: I felt that the amount of the three hundred and sixty-six (366) was definitely not required. And I -- the first priority was to free up the dollars. So went through and reduced by $100 million as a first swipe. As we developed detailed plans, and we have those in place right now, for each of those projects and each of them are cash flowed appropriately now.

MR. ANTOINE HACAULT: Okay. You wouldn't be able to point me in -- to any IR response, or any document in your filing that would give me an explanation, for example, of what you're going to be spending on in 2024/'25 and 2025/'26, would you?

MR. LORNE MIDFORD: I suspect it hasn't been included through an IR process.

MR. ANTOINE HACAULT: The only IR I had found was that no projects have been identified after March 2018.

MR. LORNE MIDFORD: I have the list in front of me. So there are projects -- there's about nineteen (19) projects spanning right now from 2018, and I can give you the -- 2018, there's 24 million; 2019, thirty-five (35); 2020 there's forty-one (41); 2021 is 24 million; 2022 is thirteen (13); 2023 is seven (7); and 2024 is one-point-two (1.2).

MR. ANTOINE HACAULT: And what's -- okay. One (1) last going back to Coalition/ Manitoba Hydro Round 1–7174 (sic). This was the justification for the phase 1A. And at 298, I think is where I want to take the witness in this PDF. Maybe just up to 297. At the bottom of 297.

Now, the reason I'm taking you to this area is in the previous CPJs that we looked at that -- one (1) of which, 1, 2, and 3 were all blanked out as commercially sensitive information, but the same headings here were not. So I'd like you to please explain to me what is meant by damage to local stakeholder relationships in number 1 of risk analysis.

Which stakeholders and what damage?

MR. LORNE MIDFORD: Manitoba Hydro lives and works in the traditional lands of the Fox Lake Cree Nation. And we live together in parts of Fox Lake -- some of Fox Lake members live in Gillam, and some live in Bert (phonetic). And those that live in Gillam share in the facilities that are provided through the town of Gillam, for instance. And so investments in recreational centres and libraries and things like that would as well, the members of the Fox Lake Cree Nation that live in Gillam would have advantage to use those facilities as well, and do.

MR. ANTOINE HACAULT: Okay. Thank you. And with respect to number 2, the work in the Gillam redevelopment expansion program is non-core business to Manitoba Hydro, and there's an indication that building houses and shopping centres may provoke negative public perception.

Is shopping centres part of what I didn't see in the blanked out stuff?

MR. LORNE MIDFORD: I'm not sure what was in the blanked out.

MR. ANTOINE HACAULT: Okay. Has Manitoba Hydro -- has Manitoba Hydro been involved in building shopping centres as indicated?

MR. LORNE MIDFORD: There is a shopping centre in the town of Gillam.

MR. ANTOINE HACAULT: And –

MR. LORNE MIDFORD: And that is -- has been built in the last five (5) years.

MR. ANTOINE HACAULT: Yeah. And is Manitoba Hydro involved at all in the financial payment for anything related to a shopping centre?

MR. LORNE MIDFORD: The capital requirements --

MR. ANTOINE HACAULT: Okay.

MR. LORNE MIDFORD: -- for that investment through the town of Gillam.

MR. ANTOINE HACAULT: Yeah. And with respect to the first bullet, the damage to local stakeholders.

Is that a positive or a negative thing? I'm trying to understand that because I, quite frankly, was reading it two (2) different ways. So I will listen. There might be damage to local stakeholder relationships if -- we saw that Manitoba Hydro was spending that much money in Gillam, but not on the First Nations was one (1) reading I had, and there might've been an alternative reading.

MR. LORNE MIDFORD: We have a -- it references the harmonized Gillam development and land use planning initiatives. So we have a joint group from Fox Lake, the town, and Manitoba Hydro that meet regularly and look at the investments that are made within the community to ensure that it aligns with all the interests going forward. And so that all the stakeholders can take advantage and support the investments that are required.

MR. ANTOINE HACAULT: Okay. And I'll finish with this. If we can just go to the next page, 298, to read the rest of numbers 2 and 3, which had been blanked out as CSI on the other capital justice -- or capital justification.

With respect to 3, are there any new subdivisions that are contemplated?

MR. LORNE MIDFORD: No. And maybe I can take an opportunity just to expand on the previous risk. I look -- I view that more as an opportunity to strengthen our relationship in the community with Fox Lake Cree Nation members who live in the community. So I view it more as an opportunity than anything.

MR. ANTOINE HACAULT: Okay.

MR. LORNE MIDFORD: Mr. Hacault, could you give us the date on this document?

MR. ANTOINE HACAULT: This -- I think if we go back, Ms. Schubert, is 2012, because it's the capital justification for phase 1A. Thank you.

MR. LORNE MIDFORD: Thank you.

MR. ANTOINE HACAULT: So I think if we go one (1) page before we'll see that it's 2012, consistent with the capital justification for phase 1B, 2 and 3, which we started with this was with respect to the phase 1A.

MR. LORNE MIDFORD: Right.

> MR. ANTOINE HACAULT: And it included, the without redaction if we go to the next page, all the types of projects, subdivisions, single-family dwellings being built, Town Centre, et cetera.
>
> MR. LORNE MIDFORD: Yeah. So this -- I -- this represents, I think, what the plan was at that time. This no longer represents the current plan. [T5943-5950]

Using this one example, it appears clear that Hydro has used a ready-made template response that capital projects have no alternative, when there is clearly alternatives being advanced in each evolution of the project planning (in this case, alternatives that reduces the cost by $141 million or more). The Board should take caution regarding considering Hydro's claims regarding "no alternatives" as credible.

Further, the Board should take comfort that cuts to spending are possible, and that no serious effort has yet occurred to implement the Board's previous directives related to 'pacing and prioritization', nor to BCG's claims that $100 million in capital spending relates to "low value capital projects"[3].

[3] PUB-MFR-72 page 133 of 615

ISSUE TOPIC #11:

ISSUE: PESSIMISM IN FINANCIAL FORECASTS

Are the financial forecasts contained in MH16 Update with Interim reflective of reasonable assumptions and best-forecast inputs, or has Hydro adopted a pessimism in forecasting that leads to an unreasonably poor projected performance resulting in a higher calculated rate request?

MIPUG SUMMARY AND/OR RECOMMENDATION:

In relation to Hydro's financial forecasts, there have been methodology changes and an alteration to Hydro's outlook or 'policy decisions' that should be considered by the PUB at least qualitatively when determining the required rate increase in relation to uncertainty and future financial impacts. This includes loads (all scenarios assume the adverse impacts of a 7.9% rate increase on sales volume, even the scenarios which do not include a 7.9% rate increase), export prices (policy decision to exclude the best estimate of market forecast values), and interest rates (2017 has yielded long-term interest rates that were below the MH16 Update with Interim assumptions).

MIPUG does not have access to any modelling associated with these factors. However, in any financial scenario the Board reviews, it should remain mindful as to whether these pessimistic assumptions are inherently built into the forecast, and adjust the Board's expectations upwards accordingly.

DISCUSSION AND SUPPORT:

Hydro's financial forecasts are made up of an innumerable range of assumptions, projections and inputs. In preparing these inputs, Hydro must demonstrate balance to yield a financial forecast that is a best forecast of expected conditions, with relatively equal probabilities of being high or low. Hydro expressed this concept as part of the GRA filing (Tab 4, page 24) that: "By the end of the 10-year forecast period, there is a 50% chance that Manitoba Hydro will achieve the minimum 25% equity ratio target."[1] The intent of the financial forecast is not to specifically skew towards pessimistic nor optimistic forecasts.

This principle is at issue with respect to a number of aspects of Hydro's scenarios built in the MH16 Update with Interim assumptions, as set out below

[1] GRA filing, Tab 4, page 24

Inclusion of price elasticities in 2017 load forecast:

Hydro prepares a load forecast with future consumption estimates in part based on assumptions about how Hydro's prices will change, and the customer load response to price changes (known as "elasticities"). In most GRA filings, the degree of rate change at issue is relatively small, so no load forecast scenarios are prepared reflecting different load developments depending on the rate change assumptions modelled. In practice, Hydro will vary the rate change among various IFF scenarios but will not vary the load forecast for each IFF run.

In this current proceeding this is not the case. The degree of rate change is material to the degree of load response expected from customers. This issue is captured by the Exhibit MIPUG-29 which shows that while the 2017 load forecast has decreased by 7% by 2026/27 in relation to the 2013 Load Forecast (used in the NFAT), the majority of this decrease (approximately 5.3%) is directly resulting from price elasticities; that is, Hydro includes from domestic customer usage decreases if 7.9% rate increases are granted.

When Hydro models alternative scenarios, including those with much lower rate increases (e.g., Exhibit MH-93, or the new Exhibit MH-140) the load forecasts for each of the scenarios with rate increases in the 3% to 4% range are materially understated, and as such the financial performance is similarly understated.

If the PUB does not grant the 7.9% rate increase but instead grants, for example the 3.36% to 3.57% range recommended by MIPUG, any IFF that models this rate scenario should be adjusted to be higher than the MH16 Update with Interim Load Forecast, which will result in higher domestic energy usage than otherwise modelled.

In effect, there is a financial upside to granting lower rate increases that Hydro has not incorporated into its forecasts.

Removal of capacity and dependability value for export price forecast:

Hydro includes in its financial forecast the value of sales expected to be derived from the export market based on signed contracts. However, for the purposes of this hearing, Hydro notes that it no longer assumes it will secure any capacity revenue or dependability premium associates with firm energy it can take to market that is not under a currently signed contract. This approach was described by Daymark in pessimistic terms:

> We conclude that MH's export revenue forecast is conservative/low relative to a value that is consistent with MH's stated goal that it will have a 50 percent chance of achieving the equity ratio target within 10 years.[2]

Daymark goes on to describe Hydro's approach as "conservative"[3], "very conservative"[4], and "extremely conservative"[5].

There has been considerable discussion in the hearing regarding the long-term benefits of the upcoming US Interconnection capital project (MMTP/GNTL) when in service in 2020 as well as future export contracts and their incorporation into the financial forecasts, including the potential for renewal of Northern States Power (NSP) contracts totaling 850 MW of a variety of capacity and energy (tr. Page 1879). These arrangements are up for renewal in 2025. Major contracts with Northern States Power started in about 1972, with large-scale transfers of capacity and energy starting in about 1976, totaling almost 40 years of consistent power supply arrangements (Tr. page 1880).

Under cross-examination from Board Counsel, Hydro witnesses offered the following explanation:

> MR. BOB PETERS: Can you explain to the panel what has happened, Mr. Cormie, with respect to the capacity value that Manitoba Hydro would want to obtain for it -- from -- for its energy and its capacity? What's changed since 2015?
>
> MR. DAVID CORMIE: And what has changed is that Manitoba Hydro has taken out the capacity revenue from the forecast that we had previously assumed that we would be able to include in our revenue forecast. That is -- has been a policy decision based on the fact that we do not have signed term sheets in place for that -- those capacity sales.
>
> …
>
> MR. JAMES MCCALLUM: … I'll maybe add a couple of points here. In this forecast we've elected to take out capacity values for contracts we don't have. So past forecasts would have assumed we are able to find a

[2] Daymark Exports Report Final, Exhibit DEA-1, Page 1.
[3] Daymark Exports Report Final, Exhibit DEA-1, Page 74, in respect of dependable energy premiums
[4] Daymark Exports Report Final, Exhibit DEA-1, Page 72, in respect of capacity revenue.
[5] Daymark Exports Report Final, Exhibit DEA-1, Page 73, in respect of no assumed renewals of longstanding contractual relationships

> counterparty and agree to a dependable contract at an assumed price where we would receive this capacity value.
>
> For this forecast we've taken that out. The point of view being that while Mr. Cormie continues to work very hard with his team trying to find additional counterparties, this is not easy and can't be counted on. And back to some comments we made last week around the importance of what we put into a financial forecast or financial model, we can't kind of continue a pattern of assuming too many good things happen. [T1268-1271]

The conservatism in Hydro's approach was described in the following exchange with the Chair:

> MR. JAMES MCCALLUM: … What I think Mr. Hacault is getting to is that in the case of Northern States Power in 2025 a contract we have, which includes capacity value and a price for our energy falls by the wayside. And so, from 2025 onward we're assuming that energy. We're not achieving a capacity value and we're not achieving a dependable energy value. And we're instead getting the assumed opportunity price, the same price we get for our excess water.
>
> THE CHAIRPERSON: Right. Right. I guess the question I was going to follow-up with, is that a change in policy or was the policy in terms of how you record that consistent? I mean, have you changed that policy at some --
>
> MR. JAMES MCCALLUM: We changed that policy. In the past what would've happened is, we would've -- we'd have, for example, this Northern States Power contract. We would have assumed a renewal. Now, we wouldn't have necessarily assumed a renewal at the same pricing. We also have forecast pricing of capacity values and dependable firm values, and those two (2) have been heading south.
>
> But we would have in past integrated financial forecasts assumed that in -- again, eight (8) years out that when this contract renews somebody, a customer X, could be Northern States Power renewing or somebody else stepping into that available capacity is. And we have a contract with a forecast of those contract terms.

> THE CHAIRPERSON: And the assumption for the price you would've charged, right now it's your -- it's being, I would assume, lower to an opportunity price. In the previous -- under the previous methodology, what price would you have assumed?
>
> MR. DAVID CORMIE: The prices for power and energy would be based on the Manitoba Hydro's export electricity price forecast, which was the consensus. [T1885-1886]

The policy decision to include no revenue from capacity sales or dependability premiums leads to the effective assumption that Hydro will be taking a premium product – firm power – to market at a price reflective of a low value product – opportunity power, as noted by both Daymark and Hydro's own witnesses

> MR. DANIEL PEACO: … But the real problem is that they've assigned zero value to capacity and energy, which essentially means that they've assumed that they're going to have no new firm energy contracts for the twenty (20) years. [T4205]

As to Hydro's witnesses, the same evidence was provided:

> MR. ANTOINE HACAULT: … What type of sale, I'm not looking for amounts, but what type of sale is assumed for forecasting purposes once those contracts come to an end?
>
> MR. DAVID CORMIE: I'll have to let Ms. Carriere speak to the assumptions around post 2025.
>
> MS. LIZ CARRIERE: It's assumed that that energy is into -- is still available as a firm sale, but it's priced essentially at opportunity prices. [T1881]

These discussions are relevant for the consideration of the PUB in that the large amounts of borrowings that Hydro is undertaking to build these major capital projects result in increased reliability and increased energy and capacity transfer capabilities for firm power from the northern generation stations to the export markets:

> MR. ANTOINE HACAULT: Okay. And could you talk a little bit about the opportunities that are going to open up to Manitoba Hydro by having the option of expanding your market for electricity into the Wisconsin area? How does that work in the small utilities in that area?

MR. DAVID CORMIE: As part of the new 500 interconnection project with Minnesota, Manitoba Hydro was able to acquire 500 megawatts of new firm transmission rights into Wisconsin. The Wisconsin market is as large as the Minnesota market is, and so we took advantage of that opportunity to acquire those transmission rights when we began on the Great Northern Transmission Line Project.

And that expands the suite or the portfolio of utilities that we would deal with in the US to include all the Wisconsin utilities. And once the Great Northern Transmission Line comes into service, we will acquire those rights. And we have been active in the States, making our presence known as a supplier of renewable, non-emitting, competitively-priced power and we're -- continue to having a presence there, both with the utilities, but with the regulators, and with the politicians to let them know that we'll be arriving and prepared to do business with them.

MR. ANTOINE HACAULT: And could you remind that this Board in relation to the 2025 year timeframe, when this Corporation expects to have that transmission facility completed into the market?

MR. DAVID CORMIE: The Great Northern Transmission Line is scheduled to come into service on June the 1st, 2020, and MISO is obligated on that date, when the line goes into service, to grant us the transmission rights, the MISO transmission rights that we reserved, and they will become available for our use at that time.

MR. ANTOINE HACAULT: And when you refer to that market -- hopefully I'm not repeating what you said, or I just want to make it clear, does it nearly double the size of Manitoba's market into the United States of America?

MR. DAVID CORMIE: In terms of US load, yes. There's an equivalent amount of load in Wisconsin as there is in Minnesota. And so potentially, you have more utilities looking for competitively-priced power, so more competition, more opportunity for Manitoba Hydro.

MR. ANTOINE HACAULT: So this new line, is it fair to say is a good thing from a competition perspective? It provides something to Manitoba Hydro in 2020 which would not otherwise have existed if that line had not been built?

MR. DAVID CORMIE: Yes. In the long run, we expect that. We have not included any revenue from an expanded market into the IFF. There is that potential, but that would be many years out into the future. Wisconsin

> utilities are -- to the extent that they needed resources in 2020, they've already contracted for those resources, and so, you know, we would be -- we -- it would be towards the end of the decade that we would be thinking that there might be some new opportunities. So it's a long-term strategic play that we've made.
>
> We want access to the market. We can do that, essentially, at no incremental cost to building the transmission line into Minnesota. So we took the opportunity, and we're going to work the market to rate benefits down the road for the Utility. [T1969-1974]

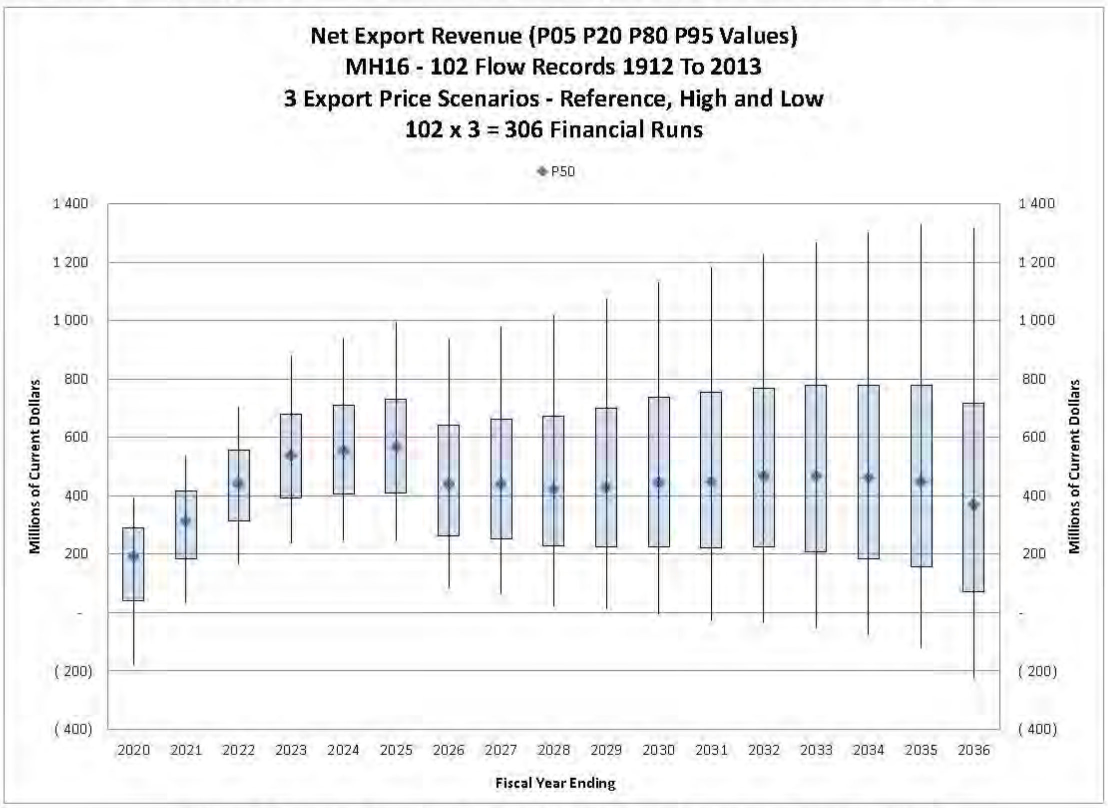
Further testimony on the future likelihood of pricing above opportunity market benchmarks was provided under cross-examination by Board Counsel:

> MR. BOB PETERS: And from your evidence this morning, the suggestion was that Manitoba Hydro should be able to extract higher export prices if they ship energy into Wisconsin?
>
> MR. DAVID CORMIE: What I indicated in my testimony was that in the bilateral market for the long -- sale of long-term firm power, Wisconsin is a higher cost market than Minnesota and so it creates opportunities for Manitoba Hydro to sell long-term firm power over the firm transmission associated with the project. So those are the opportunities.
>
> Spot market electricity is priced at the border, whether it goes into Wisconsin or Minnesota. So the opportunity market doesn't make any difference, but from a bilateral perspective, it provides more -- a larger customer base.
>
> MR. BOB PETERS: Mr. Cormie, have the higher prices for bilateral agreements in Wisconsin been reflected in Manitoba Hydro's export revenue forecast?
>
> MR. DAVID CORMIE: There are two (2) contracts in the export revenue forecast for the sale of firm power to Wisconsin public service. One that we're currently engaged in delivering to, and one that commences in 2021 as a result of the construction of Keeyask. Those are very attractive prices for Manitoba Hydro.
>
> MR. BOB PETERS: Those prices are included in the export price forecast?
>
> MR. DAVID CORMIE: Yes.

> MR. BOB PETERS: And so are there any additional bilateral agreements in Wisconsin included in the export forecast other than the two (2) that you've referenced?
>
> MR. DAVID CORMIE: No, we're building the market in Wisconsin as we speak. [T5822-5824]

Visually, the following uncertainty analysis graph from PUB/MH II-41a-b shows the dip that occurs in Hydro's forecast export revenue in 2025/26 from the policy decision to not include any premium in pricing of future sales, the effect that Daymark called conservative:

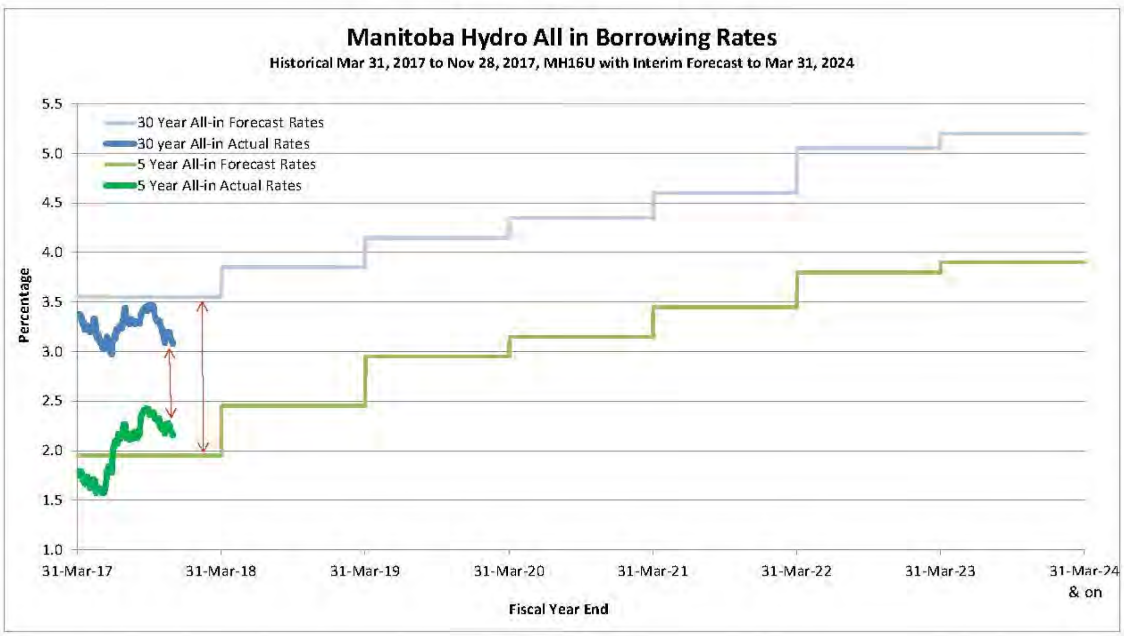
Figure 4.10 MH16 Update with Interim - Net Export Revenue Variability



In summary, the preparation of a best forecast financial projection should not assume zero value for valuable products (capacity, dependable energy). Such an assumption is by definition the worst case scenario, not the best forecast. Further, such an assumption is internally inconsistent with Hydro's own approach to describing the IFF projections, as being effectively P50. There is no reasonable basis to take a "P100"[6] pessimistic assumption in MH16 scenarios.

Long-term actual interest rates (30 year) are lower than forecast

While Hydro states that increased short-term (5 year) interest rates are increased from forecast, resulting in reduced benefits to the 12 year WATM strategy, the 30 year interest rates have been lower than what is included in Hydro's forecasts by up to 0.5% recently, as shown in the graph below from MH-68 slide 64.



While there is no evidence that any such interest rate benefits will necessarily continue into the future, just the savings arising from the period covered by the actual interest rates in the above graph will translate to substantial finance expense savings for debt that is being locked in for long periods of time. Hydro's borrowing requirements include $2.5 billion in borrowings for 2017/18 or roughly $10 million per working day, which would have been locked in at lower than anticipated interest rates for long-term borrowings. This benefit is not fully represented in any scenario based on MH16 Update with Interest assumptions.

While interest rates do remain at historic lows, the above figure also illustrates that Hydro's forecasts are not based on rates remaining at this level. Hydro has appropriately assumed that some degree of interest rate rise should be incorporated into forecasts, consistent with third party forecasts used by Hydro. As a result, the Board should not be

[6] Daymark testimony (Peaco), Transcript 4206.

led to understand that any interest rate rise is harmful to the MH16 Update with Interim assumptions – interest rate rises are already planned for and incorporated into the projections (shown in the figure by the light blue stepped line).

ISSUE TOPIC #12:

ISSUE: DEMAND SIDE MANAGEMENT (DSM) CONSIDERATIONS

Do Hydro's financial forecasts reflect reasonable assumptions regarding the scale of DSM consistent with integrated resource planning?

MIPUG SUMMARY AND/OR RECOMMENDATION:

Given that all the evidence on the record shows that Hydro's current planned levels of DSM spending and DSM energy savings results in increased costs and reduced revenues, at a time when export prices (and related marginal costs) have materially declined, it is not apparent that Hydro holding a "status quo" assumption regarding DSM is reasonable. Such DSM-related load reductions have also been referred to a "sub-optimal" by the Board's Independent Expert Consultant, Dr. Yatchew.

The Board should only include in Hydro's financial forecast a level of DSM spending consistent with the principles of Integrated Resource Planning. Such principles would hold that when marginal costs plummet by approximately 1/3 (as occurred in this hearing) the level of DSM spending and load reductions should be materially reduced.

If this is not adjusted in Hydro's financial forecasts, pending resolution of the government-ordered conservation targets for Efficiency Manitoba, the negative impact on rates should be viewed as an additional new government charge.

Where DSM is proven cost-effective, including where it can benefit customers to manage electricity bills without negatively impacting other ratepayers, it should be encouraged. This should also include ongoing work on Codes and Standards, and Low Income programming.

DISCUSSION AND SUPPORT:

Manitoba Hydro's DSM plan (Power Smart Plan) is not explicitly before the PUB for recommendation in this proceeding. However, the level of spending included in Hydro's financial forecast results in both increased capital costs and decreased revenues, as well as a major outflow of cash. In the interim, before a DSM plan can be reviewed by the PUB from Efficiency Manitoba for cost-effectiveness and other benefits (including environmental), the levels of proposed DSM spending should be considered in regards to negative ratepayer impacts.

Hydro's financial forecast (MH16 Update with Interim) and load forecast incorporates the costs and savings reflected in Manitoba Hydro's current Power Smart Plan as a placeholder until the new efficiency entity is in place and the first plan is developed. The new Crown Corporation, Efficiency Manitoba, will assume responsibility for efficiency initiatives to focus on reducing electricity and natural gas consumption in Manitoba, with mandated targets in excess of those embedded in Manitoba Hydro's existing DSM plan.[1]

MIPUG recommends that consideration be given to the level of impact DSM savings and expenditures have in the financial forecast, and on electricity rates.

As stated in MIPUG-13 in regards to the levels of DSM spending (note that this was prepared before the decline of 1/3 in Hydro's marginal cost estimates, in Exhibit MH-101):

> On DSM, the assumptions used by Hydro are based on achieving an energy savings level that fails to meet the targets of the new legislation. This is appropriate, as the legislation specifically indicates the targets cited should be revised to achieve cost effectiveness (presumably in line with appropriate Integrated Resource Planning (IRP) principles). However, Hydro's DSM proposed spending far exceeds the level that can likely be justified based on IRP principles at this time. It is clear that significant adverse rate impacts arise from Hydro's proposal, despite the purpose of the program being explicitly to "mitigate the impact of rate increases", not to drive rate increases. As a result, the appropriate assumptions for DSM in MH16 should be far reduced from the program presently included, to the benefit of both Hydro's net income and cash levels. (MIPUG-13, page 1-6)

Hydro's DSM plan proposed savings compared to legislated targets:

> MR. KELVIN SHEPHERD: … The legislation sets out efficiency goals for DSM programming that generated 22.5 percent reduction in electricity usage over fifteen (15) years. Our current DSM plan, that is reflected in this forecast, assumes achievement of a 17 percent reduction, and includes DSM programming costs associated with achieving only 17 percent. [T207]

With regard to whether aggressive DSM spending be assumed at this time, Dr. Yatchew addressed this question while reviewing MIPUG/Yatchew-3b in cross-examination:

[1] Hydro Application, Tab 3, page 12

MR. ANTOINE HACAULT: ... So first of all I'll read the question:

> "Is it Dr. Yatchew's view that a time of large surpluses and low marginal cost that declines and uses are our suboptimal?"

And you gave a very concise answer, Dr. Yatchew: "Yes." So I'll try and take that in little bites and try to understand that in the context of, let's say, for example, DSM spending, which creates additional surplus.

So firstly, would you agree with me that we are entering with this large generating station, Keeyask generating station, a period where we have quite of -- surplus energy.

DR. ADONIS YATCHEW: Yes, that's my understanding that it would take a significant period of time to absorb that additional capacity.

MR. ANTOINE HACAULT: And I don't want to get too hung up on capacity and energy, but it'll give us some of both as a generating station, correct?

DR. ADONIS YATCHEW: Well, it will give you lots of capacity. The question is how much energy you'll be getting out of it for useful purposes if there's no demand here and the export market isn't picking up enough of it.

MR. ANTOINE HACAULT: Okay. And in a very general way, when we do demand side management spending, we are freeing up, amongst other things, surplus energy?

DR. ADONIS YATCHEW: That's correct.

MR. ANTOINE HACAULT: Okay. So in the context of freeing up further energy, what does that tell us about utilizing the surplus energy of Keeyask generating station?

DR. ADONIS YATCHEW: You're delaying the point in time in the future when it is operating and providing services at close to its capacity and you've already incurred the capital cost.

MR. ANTOINE HACAULT: And I'm trying to understand your answer as to whether that's a suboptimal situation. Does that answer also apply to how much DSM spending we're doing and whether that's -- ends up being a suboptimal result?

> DR. ADONIS YATCHEW: So that's potentially part of the story here. And again, I think I've used this language here before, it's this -- the difference between rational and feel good policies. Yes, we can pat ourselves on the back that we're reducing our electricity consumption. And it's also -- there's also natural gas element to this through carbon taxes, for example. It's great that we're reducing our energy consumption, but we're reducing -- if we're reducing our energy consumption, in this case electricity consumption of a very clean source that is otherwise just spilled water, then -- and we're spending money to do that and the money that we're spending may also put pressure on total costs for Manitoba Hydro, then you want to take a look at each DSM program and see whether it is not just feel good, but is it rational.
>
> In this case, if it's creating additional excess capacity then one has to make a pretty convincing case of why the money is being spent. [T4499-4502]

Further marginal values have decreased 28% from 2015/16 to 2017/18, as reported in PUB/MH II-57 Revised, (to 4.39 cents/kWh for generation when serving residential customers). This will have the impact of decreasing DSM benefits (through less export revenues than previously assumed), and lead to reduced levels of cost effective or economic DSM[2]. To explain this further, in cross-examination with PUB Counsel:

> MR. BOB PETERS: And so when you -- when -- and I don't want to put -- get you too involved on this chart because I appreciate it will be something you haven't reviewed.
>
> But in essence, here's a whole portfolio of demand-side management programs in Manitoba and those programs are listed on the bottom and the funding for them is shown in the bar charts where the Utility, in blue, puts in the money or the customer, in green, puts in the money.
>
> You can see that?
>
> DR. ADONIS YATCHEW: Yes.
>
> MR. BOB PETERS: And there's a lot -- there's some metrics on the page, such as the average levelized marginal value and there's also the portfolio levelized resource cost on the far right-hand side and the levelized utility costs.

[2] MIPUG-26, slide 41

You can see those numbers?

DR. ADONIS YATCHEW: Yes, I can.

MR. BOB PETERS: Can you clarify for the Panel that when you're making a rational decision on demand-side management, is it rational -- does it have to be rational to the consumer or is it rational from the Utility's perspective?

DR. ADONIS YATCHEW: So when I speak of rational, I really mean, what are the -- whether the policy itself is rational. And the consumer, herself or himself, is presumably making rational decisions. I won't get into the potential for deviation from what are optimal rational decisions.

But yes, we're really talking about, is it rational from the perspective of the decarbonization policy; is it rational from the perspective of the Utility's revenues and costs?

MR. BOB PETERS: Is there a screen that you could recommend as an economist to how do you screen for what is rational and what isn't?

DR. ADONIS YATCHEW: I can't comment specifically on these DSM programs here.

MR. BOB PETERS: I appreciate that. And I'm not asking you to do that. I'll ask you in a general way, please.

DR. ADONIS YATCHEW: But in the present context, when you've got lots of excess capacity and the marginal cost of producing electricity from that source is low, is very low, then it's hard to justify reducing consumption, expending expenditure -- having expenditures on reducing consumption when the environmental consequences of that consumption are minimal.

I'm hesitating to give you a formula, but the first thing I would probably look at is: How much are you -- what is the cost of reducing consumption by 1 kilowatt hour measured against the cost -- the marginal cost of producing that electricity?

So it's the marginal cost of producing, in this case, green electricity against the cost of reducing that consumption by 1 kilowatt hour. That would be my instinctive and, let me just say, very provisional answer.

MR. BOB PETERS: No, I thank you for that. I'm going to follow a little bit further and I've reviewed material again that I don't expect you will have reviewed in any detail or maybe even at all, Dr. Yatchew, and that's information that was authored by an organization called the Boston Consulting Group.

And in their materials, they refer to rate increases as the ultimate DSM program. And if you think about it, there's zero resource cost needed from the Utility. There's au -- you know there's a hundred percent participation by your customers and you're telling us today that there's going to be a price elasticity impact.

So from that perspective, these rate impacts can accomplish what some DSM programs would be aimed to do? Do you accept that?

DR. ADONIS YATCHEW: Yes. And in fact, that's why I was careful in the language that I used in the report because these price increases will themselves capture DSM effects. These price increases will capture DSM effects.

In fact, when you look at all these elasticity modelling studies, very, very few of them actually try to filter out the effects of DSM programs on demand versus the effects of price. The Utilities try to do that because Utilities are being required in many places to produce DSM -- measurable DSM program results.

MR. BOB PETERS: So I interpret your answer, Dr. Yatchew, to be telling the Panel that it's not appropriate to think of Manitoba Hydro's rate changes in the manner of a DSM program because, as you've said, there's lots of excess capacity and there's a low marginal cost, and therefore, it would be hard to justify on a rational basis spending of money to reduce consumption to generate even more surplus?

DR. ADONIS YATCHEW: Yes. [4567-4571]

The Boston Consulting Group provided options to the Manitoba Hydro Electric Board to reduce DSM spending which could result in $30 to 65 million in annual capital expenditure reductions and $11 to 22 million in annual revenue increases for the next five years[3]. This was discussed at a high level by Mr. Kelvin Shepherd in cross-examination:

[3] PUB-MFR-72 page 220 of 615

MR. ANTOINE HACAULT: We'll backup one (1) slide in this material. This is another slide from the Boston Consulting Group, correct?

MR. KELVIN SHEPHERD: Yes, this was part of their material.

MR. ANTOINE HACAULT: And it's pretty hard to summarize this, but am I getting the slide correctly, that if there was a change in the approach in investment over DSM over the next five (5) years that the Utility could achieve two (2) things: Firstly, a reduction in costs, correct?

MR. KELVIN SHEPHERD: Perhaps I'll just wait till you go through your conclusions.

MR. ANTOINE HACAULT: Correct?

MR. KELVIN SHEPHERD: The change you're talking about is a reduction in the DSM program?

MR. ANTOINE HACAULT: Yeah, that would result in --

MR. KELVIN SHEPHERD: Really a reduction in the DSM program would take less cost to implement it, yes.

MR. ANTOINE HACAULT: And for reasons which I'll get into a little bit later with the revenue panel for the new members of the Public Utilities Board that, in fact, increases Manitoba Hydro's revenue.

So you spend less on DSM and that increases Manitoba Hydro's revenues, correct?

MR. KELVIN SHEPHERD: With spending less you have less efficiency, you have more load and with more load you have more revenue, yes.

MR. ANTOINE HACAULT: And more revenue at a higher domestic price rather than putting it on the opportunity market and exports; correct?

MR. KELVIN SHEPHERD: Yes, that's basically correct. [T412-414]

With respect to BCG's recommendations, Hydro has not provided evidence that it is in any way responding to the financial pressures BCG highlighted in respect of DSM expenditures, even though Mr. Kelvin Shepherd reported the following:

DR. BYRON WILLIAMS: And, sir, is there a documented formal follow-up process within Manitoba Hydro tracking how it is responding to the advice of Boston Consulting Group and its recommendations?

MR. KELVIN SHEPHERD: Could I just ask you to repeat. So you're asking is there a formal follow-up...?

DR. BYRON WILLIAMS: So, sir, let me try it in little pieces.

MR. KELVIN SHEPHERD: Yeah.

DR. BYRON WILLIAMS: There was a lot of advice given to the Manitoba Hydro board and to Manitoba Hydro by Boston Consulting Group; agreed?

MR. KELVIN SHEPHERD: Agreed.

DR. BYRON WILLIAMS: There were important benchmarking exercises undertaken; agreed?

MR. KELVIN SHEPHERD: Agreed.

DR. BYRON WILLIAMS: There was a whole strategy in terms of approaches to the export market and recommendations related to that, sir?

MR. KELVIN SHEPHERD: True.

DR. BYRON WILLIAMS: And what I'm asking you, sir, is Manitoba Hydro formally following up with those recommendations and is there some sort of documentation of how it is responding to those recommendations, sir?

MR. KELVIN SHEPHERD: I'd say that the recommendations have largely been incorporated in our new strategy and our new plan. And so we've taken I would say output from the review, and have developed a new plan which includes various elements of the recommendations, and that's what we're tracking.

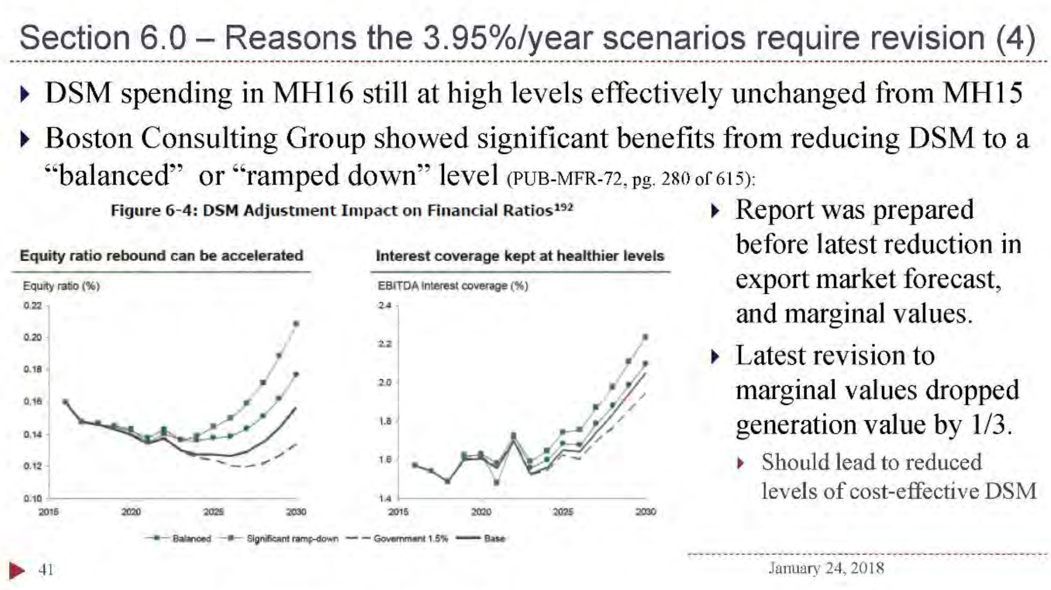
DR. BYRON WILLIAMS: And to the extent that you rejected those recommendations, sir, is there anything formal calculating or articulating that rejection?

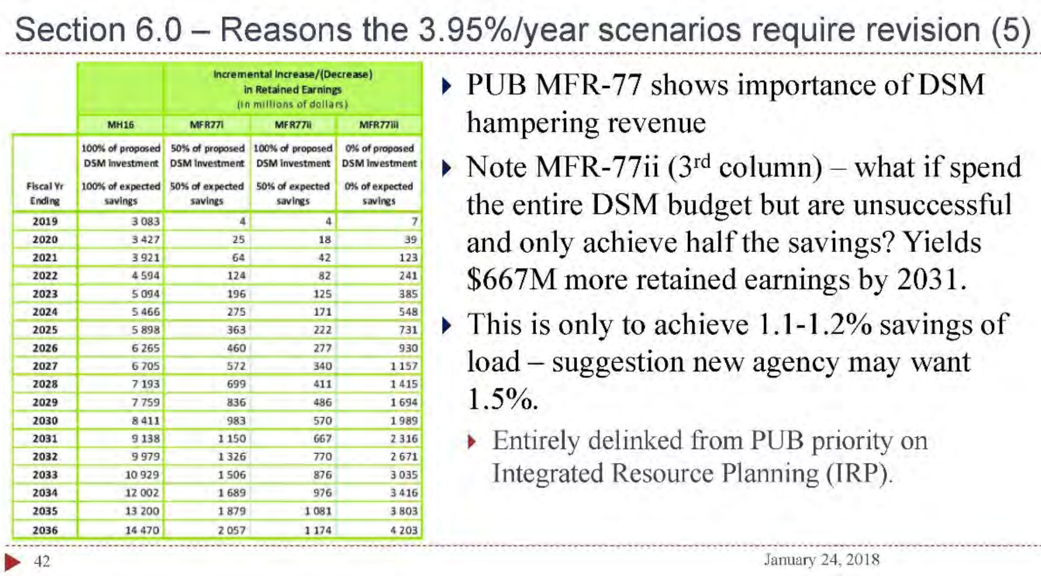
MR. KELVIN SHEPHERD: No.

> DR. BYRON WILLIAMS: And there's no written document, sir, tracking how you've responded to the Boston Consulting Group recommendations? It's just implicit in your actions, is that your evidence?

> MR. KELVIN SHEPHERD: My evidence would be that it's been incorporated into our new business plan and that we're tracking our plan which includes a number of elements and that would -- the plan's been reviewed with the Board, and that's basically how we've taken the input and learnings from the BCG report and incorporated it going forward, and we will be tracking our plan. [473-475]

As explained by Mr. Bowman, regarding PUB-MFR-77 and analysis done by BCG on financial impacts of reduced DSM spending (shown in the reproduced slides 41 & 42 from MIPUG-26):





		Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)		
	MH16	MFR77i	MFR77ii	MFR77iii
Fiscal Yr Ending	100% of proposed DSM investment 100% of expected savings	50% of proposed DSM investment 50% of expected savings	100% of proposed DSM investment 50% of expected savings	0% of proposed DSM investment 0% of expected savings
2019	3 083	4	4	7
2020	3 427	25	18	39
2021	3 921	64	42	123
2022	4 594	124	82	241
2023	5 094	196	125	385
2024	5 466	275	171	548
2025	5 898	363	222	731
2026	6 265	460	277	930
2027	6 705	572	340	1 157
2028	7 193	699	411	1 415
2029	7 759	836	486	1 694
2030	8 411	983	570	1 989
2031	9 138	1 150	667	2 316
2032	9 979	1 326	770	2 671
2033	10 929	1 506	876	3 035
2034	12 002	1 689	976	3 416
2035	13 200	1 879	1 081	3 803
2036	14 470	2 057	1 174	4 203

MR. PATRICK BOWMAN: The last point about revisions is on slide 41. And this is about the DSM spending. And as I note, DSM spending in MH-16 is still at levels effectively unchanged from MH-15. I put in some slides from Boston Consulting Group emphasizing how big a difference different DSM assumptions can make. Their slides go to 2030, which is not as far as we're talking about.

But the left-hand side shows the difference in equity ratio by only varying the amount of DSM you do. And a huge part of that is what you do to your loads in your revenues. It also shows the interest coverage ratio and Boston had Hydro run four (4) scenarios, one (1) they called balanced, one (1) they called significant ramp down, one (1) they called government 1.5, and one (1) that was a base.

And I will note that in terms of all of Hydro's forecasts of DSM the -- all the ones we're looking at were prepared with marginal values that were at the start of the hearing, not the levels that have been provided since we're been in the hearing, which dropped by about a third for the generation component. With lower marginal values much less DSM would be cost-effective.

Switching to slide 42. This just is a -- from a PUB MFR. PUB asked Hydro to run different assumptions on DSM and they -- I'm sure they are -- were run in a relatively simplified manner. But they emphasize -- the first column is the MH-16 scenario of how much retained earnings Hydro will have by year. And the next three (3) columns run different scenario assumptions about DSM, and how much better retained earnings will be if Hydro takes different assumed levels of DSM.

And the one (1) that's really interesting to me is the middle one (1), MFR-77-II, which is the third column in the table. And this is effectively, what if we spend the entire DSM budget, but we fail to achieve the savings? And the answer is we end up with a lot higher retained earnings, meaning a lot lower ability to charge a lot lower rates.

So this isn't a question of spending. This is the emphasis about how much the lost revenue from your domestic loads is a big feature. And it goes to what Dr. Yatchew was talking about, is building load in order to help pay for the new assets is -- should be a critical assumption. And I believe he called this an inefficient use of a -- an inefficient assumption, I believe. Definitely unfortunate.

And I would say DSM plans that don't change with changes in assumption in their marginal value, and don't change with changes assumptions about when your next plant is needed are not driven by an integrated resource planning framework, which is what this Board recommended. Sticking to 1 1/2 percent is not a responsive approach to reflect what would be arising from a resource planning framework.

And I have some further comments about that in the evidence that I think, notwithstanding that there is a piece of legislation saying Hyd -- the new agency will target 1.5 percent unless the Lieutenant Governor and Council or this Board recommend or -- this Board recommends the Lieutenant Governor and Council concludes otherwise.

I think at this point in time, Hydro's plan doesn't get to 1.5 percent. So I'm taking it that they've reached the conclusion they shouldn't assume 1.5 percent, and I think that's a reasonable assumption. I think in light of the facts that are there, pending this Board having the chance to have its first major review of Efficiency Manitoba's plans, I don't see the basis to assume that the largest plans that may have been assumed to be efficient at the time of NFAT should still be assumed to be the type of plan that's appropriate today when we're hearing about the financial issues, and we're hearing about the reductions in export markets. [T6097-6100]

In summary, the DSM assumptions in MH16 Update with Interim are a relic of past IFFs and do not reflect reasonable Integrated Resource Planning assumptions, nor do they reflect the updated marginal cost estimates reflective of the state of export markets.

Similar to the issue of drought cost, as export markets go down Hydro loses revenue but also sees benefits – reduced costs of drought, and reduced need to spend on DSM. Hydro has reflected the adverse impacts of the lower export prices, but has not shown the offsetting benefits either in terms of lower cost of drought, or in terms of lowered targets for cost effective DSM. All forecasts in this proceeding based on MH16 Update with Interim should be viewed through this lens – that is, they assume simply too much DSM spending, and too much erosion of the critical Manitoba loads which are needed to pay for the assets coming into service. This is particularly true if Hydro is also imposing large rate increases such as 7.9% on customers (which will already drive a degree of conservation).

ISSUE TOPIC #13:

ISSUE: UNCERTAINTY ANALYSIS AND FUTURE REGULATORY TOOLS

To what extent should the Board direct improvements to the uncertainty analysis tools, and plan for the ability to use the tools in future regulatory proceedings?

MIPUG SUMMARY AND/OR RECOMMENDATION:

MIPUG views that the uncertainty analysis tool provides the most significant advancement in the ability to understand Hydro's risk since it began being regulated. However, the tool is not advanced to a level of refinement where it can serve this purpose as yet.

The Board should direct Hydro to refine the uncertainty tool to build in, at minimum, inter-year rate response. This refinement can be tested and advanced through technical work with stakeholders (including intervenors) before the next GRA. In future GRAs, further consideration should be given to applying probabilistic thresholds to determine the appropriate rate path, where the rates to be approved should prove sufficient to avoid almost all future needs for rate shock.

As noted by Mr. Osler, the issue of Hydro's financial targets that is before the Board today is at one level a "communication problem" – a difficulty understanding just what risks and what pace of achievement is intended. Advancing the tools available to Hydro to better model and communicate possible future regulator responses to adverse conditions will help avoid miscommunication about the role of targets in future.

DISCUSSION AND SUPPORT:

Hydro's previous financial forecasts were subjected to "stress tests" in the form of deterministic risk scenarios (e.g., see IFF16, page 44). These stress tests operate such that one risk was overlaid on the IFF forecast (e.g., drought) with no other changes and the result on the financial targets is summarized.

As noted by Mr. Bowman in MIPUG Exhibit 15 (Background Paper C), this is an inferior approach to analyzing risk, as it fails to reflect three key considerations:

1) Risks overlap (high water may coincide with low export prices),
2) Risks have different levels for probabilities of occurrence (not just the worst level, such as 5 years drought), and

3) Risks occur as a feature on top of the underlying finances – for example, though a drought may cause $1.2 billion in negative effects over 5 years, if the net income was otherwise going to be $1 billion over this period, the drought only causes $200 million in net losses.

The uncertainty tool developed by Hydro as part of Appendix 4.2 addresses these three aspects of Hydro's risks. As such, it is a significant enhancement to the stress tests or risk register traditionally shown in the IFF.

Mr. Forrest addressed the importance of this advancement in response to questions from the Chair:

> MR. GERALD FORREST: Now, you're fortunate in compared to where I saw myself years ago, where you have new tools now available to you that are much more advanced than the tools that we had at the Board at that time, relative to your uncertainty analysis. So you can see those tools. You can look at it and put in your various choices and options in those tools to determine where you're going. [T6058]

The uncertainty analysis is already proving to be a useful tool. For example, this tool formed the foundation of Mr. Bowman's conclusions that Hydro was now nowhere near as risky on the downside extreme under MH16 than under MH14, as shown in MIPUG Exhibit 27, page 3.

The future potential benefit of a properly refined uncertainty tool lies not only in analysis of Hydro's risks, but also in the way this can be communicated to key stakeholders including the capital markets or even new senior management within Hydro. As noted by Mr. Osler:

> MR. CAMERON OSLER: … But, when we say 25 percent equity ratio, we happened to have been there five (5) years out of the last umpteen decades. Does that mean to an ordinary person that we have to get back there right away? Obviously it meant that to somebody who came into this job, you know, and tried to deal with -- I will assume responsibly with their obligations. And they were shocked.
>
> But from a regulatory point of view that target -- I never interpreted it to mean that type of thing. So there's a communication problem here. That target is there to give a valid basis for building up reserves to that level without reducing rates. And I fully support it for that reason, as long as the rates that we're talking about that are being used to build it up are less than inflation and certainly not more than inflation.

> Once you get above inflation, my perspective is, we're into another game and we have to be very careful about justifying that game based on hard targets that are called long-term. [T6425-6426]

In respect of communication about targets and the role of probabilities, Mr. Colaiacovo noted the example of Bonneville Power in his direct:

> MR. PELINO COLAIACOVO: ... You do need some cushion to manage those eventualities. But Manitoba Hydro has not made a specific argument that says, here's how much we need to manage that risk. And here's how much we need this year. And here's how much we need next year. And here's how much we need the year after, right. They've asked for a blanket target of 75 percent debt; not particularly focused in on this risk that needs to be managed, which is a big risk and which is of import in any capital markets' analysis.
>
> Another Utility Bonneville Power Authority, which is in a similar situation to Manitoba Hydro in that it is mostly driven by hydrology has a very specific rule and their rule is our rates have to be sufficient so that we can manage 95 percent of all hydrological outcomes, without having to go back and ask for different rates for the next two (2) years. It's a rule. They talk about it in their debt presentations, right. And so everybody knows that's how they set their rates. They set their rates so that they don't have to go back for new rates as long as it's not in the 5 percent tail, right. And that rule provides comfort to the market. They know what they're doing and they're managing.
>
> And they also say if we are in the 5 percent tail then we will go back and ask for higher rates to compensate for the fact that our hydrology has deteriorated into that 5 percent risk tail. So it's -- again, tell the markets what you're going to do, and then you actually have to do it, if the situation arises. [T4908-4909]

In the above example, Mr. Colaiacovo illustrates a two-fold benefit of refined probabilistic modelling. First, capital markets can receive this information as part of debt presentations, and receive confidence that today’s rates (and rate path) are able to address most future conditions without default. Second, customers can understand how today’s rates fit into building reserves that buy customers future rate stability. This concept was noted by Mr. Bowman under cross-examination by Board Counsel:

> MR. PATRICK BOWMAN: … When you look at the structure of this type of Utility and similar ways that -- similarly structured Utilities have been --

> had been dealt with in the past, the idea is Hydro's cost recovery operation. It's going to recover its costs from customers. So, it can do that every year and pay its bills. But, in the interests of rate stability, to the benefit of customers, it can be better for customers to pay a certain amount earlier on to build up the reserve so that they buy themselves future rate stability. And I think that's the clearest trade-off is the retained earnings or the reserves are for customers because they're amounts that the customers paid up to help buy themselves future stable rates. [T6419-6420]

With a refined uncertainty analysis tool, this type of communication, including the concept of probabilities, becomes possible. However, to achieve this, the model will need to include a measure for "rate response", as discussed in Mr. Bowman's Background Paper C (MIPUG-15, pages C-9 to C-11):

> The most notable omission from Hydro's uncertainty analysis is the failure to include any mechanism for automated rate response in the analysis. This means that the scenarios show excessive divergence from targeted financial performance as rate increases continue to be enforced by the model in situations where they are nonsensical. For example, the model may show that there is a risk, if a 3.95%/year rate regime is implemented, that equity will turn negative and continue eroding, or at 7.9%/year that Hydro will exceed 50% equity and $1 billion in net income yet continue to raise rates. The result is that the projected cones are much wider than can reasonably be expected.
>
> …
>
> In the case of Hydro's current uncertainty analysis, this could be implemented by modelling a rate regime based around a given starting baseline percentage increase, but if conditions trended adverse, an increase somewhat higher than this level could be used (e.g., 2% higher than baseline)[1] and if conditions were better than expected, a lower than baseline increase could be assumed (e.g., 2% below baseline). In each scenario, for each year of the model, the calculation would start with assessing which rate increase would be implemented.
>
> The results of such modelling would yield two beneficial results:

[1] In the last major drought – 2004 – the PUB decided to implement a 5% rate increase, compared to a 3% sought by Hydro. A reasonable inference could be that 2% above baseline is an accepted response to adverse conditions occurring.

1) The modelling would permit answering critical questions – including whether a 3.95%/year pathway (recognizing the potential for a 5.95% increase if conditions are significantly poor, and 1.95% if conditions are above expectations) would provide sufficient or potentially even excessive risk protection. This could be compared, for example, to scenarios with a 3%/year baseline and a +/-3% boundary or other alternatives, offering a lower initial rate increase to customers but perhaps a slightly higher risk of instability in rates.

2) The modelling would allow the PUB to signal endorsement of not only a current rate increase, but a possible future pathway (including pre-assessed rate responses) to address Hydro's known risks should they arise. This has the potential to provide an added degree of comfort and clarity to lenders and credit ratings agencies about the regulatory responses that are able to be brought to bear to deal with future adverse conditions, though such signalling would not be intended to in any way fetter the Board's discretion to act according to the best evidence at the time each future rate increase is sought.

Mr. Bowman expanded on this concept under cross-examination by Board Counsel:

> MS. DAYNA STEINFELD: And if we just move forward to slide 23. In terms of taking next steps in this regard, does the uncertainty analysis that's set out here is this something that might help form the basis for the Board to set those kinds of refined ratesetting mechanisms?
>
> MR. PATRICK BOWMAN: The analysis behind that slide is the tool that is, I will say, well thought out and rather elegant. Taking it to the next step would involve -- this isn't the slide I would use, this is just a -- how bad does it get at some point. There's a different sort of set of cone type of analysis.
>
> …
>
> What you should do is say, If I look at the condition to each year and have a rule for how I might change my rate increases and not rate shock people, how bad does it get?
>
> In other words, not what does it look if I do 3.95. It'd be -- my suggestion is the next step you test, as you say, what if it -- what does it look like if I

> start at 3 but if things are going downhill, I'm prepared to do 5 and if they're going uphill, I'm prepared to 2. And then have a model that adapts that way and see how tight you pull in that range.
>
> And if you -- when you -- once you pull in that range, your P5 or something of that nature is still keeping your retained earnings way above of Mr. Osler's measure of minimum retained earnings, and I think you have some comfort that you have a regime that, you know, you can start with that rate increase 3 percent. You've communicated to people that if things go bad I'm going to go to 5. No one's sitting there thinking you're going to go to 12. And you've shown how that will avoid the bottom, and you're not going to drive this Utility into ruin.
>
> I thinks that's the type of communication that this tool can do if it's developed to its level. It's not quite there yet. [T6428-6430]

As to next steps, Mr. Bowman addressed recommendations under cross-examination by Board Counsel:

> MS. DAYNA STEINFELD: … So is your recommendation to this Board that it move in this direction perhaps by ordering a next steps such as a technical conference; is that what you're suggesting?
>
> MR. PATRICK BOWMAN: That would be one practical way. [T6428]

ISSUE TOPIC #14:

ISSUE: COST OF SERVICE METHODS AND CUSTOMER SERVICE GENERAL (C10)

Does the Cost of Service study filed with Hydro's GRA (PCOSS18) reflect proper implementation of the Board's Order 164/16 and an appropriate response to the directives contained in that Order?

MIPUG SUMMARY AND/OR RECOMMENDATION:

For all matters other than the Customer Service (C10) allocator, MIPUG confirms the cost treatment of PCOSS18 follows the directions or principles of Order 164/16.

With respect to the costs included in the C10 subfunction, Hydro has not demonstrated that these costs relate to the GSL 30-100 kV nor GSL >100kV classes. The information Hydro has provided suggests that these costs are predominantly related to distribution level assets or service to smaller customers (including contact center – outages, line locates and building moves & safety watches), of which larger GSL customers do not use, or relate to activities that are served to GSL >30kV customers through the C23: Industrial & Customer Solutions subfunction (including contact center and marketing R&D) of which these classes are already solely allocated these costs.

It is the recommendation of MIPUG that C10 costs, other than Education & Safety and Rates & Regulatory, are not allocated to the GSL 30-100 kV and >100 kV classes. If these costs are to be allocated to all customers, MIPUG recommends that this either occur through including these costs in the distribution function and be allocated to customers based on their share of the distribution system usage, or that they be allocated on the basis of unweighted customer numbers.

DISCUSSION AND SUPPORT:

Manitoba Hydro has implemented Board directives from Order 164/16 in the Prospective Cost of Service Study for Year Ending March 31, 2018 (PCOSS18). In general, MIPUG confirms the cost treatment of PCOSS18 follows the directions or principles of Order 164/16 except for the implementation of Customer Service General Costs, known as C10.

Hydro has proposed a new treatment for Customer Service General costs in PCOSS18, splitting the previous C10 costs into three separate subfunctions – C10: General

Customer Service, C13: Customer Service – Small Customers, and C23: Industrial & Customer Solutions.

For the costs included in the new C10 subfunction, which total $13.9 million, relate to: contact center – outages ($1.2 million), rates & regulatory (3.0 million), marketing R&D ($1.3 million), line locates ($4.1 million), and building moves & safety watches ($3.1 million). Hydro proposes to allocate these costs by customer class weighted by class revenue.

MIPUG agrees that the allocation of C23 related costs should be exclusively expensed to the GSL classes. However, Hydro has not provided any evidence that the costs associated with the C10 function are caused by the GSL classes or that these costs are adequately charged to GSL classes already through the services provided in C23 function (Marketing R&D and Contact Center - Outages). As explained by Mr. Bowman in his direct examination:

> MR. PATRICK BOWMAN: … The only issue I comment on is customer service C10, and you will have heard some of these issues be canvassed already in this hearing. The sum total of the issue is, in my submission, about $2.6 million being allocated to the three (3) general service large classes.
>
> That is not supported. It's either functions that are not driven by the bulk power systems. They are driven by the distribution system. Or it's functions in which they are already paying for through another route. Or it's functions that don't relate to the type of services that they receive, at least in the vast majority of services are not provided to them. And it's material in a sense as it's about 1 percent of the GSL cost. It's not earth shattering, but it's big enough that I think it merits adjustment in the cost of service study. [T6101-6102]

Regarding the 'functions in which they are already paying for through another route', this refers to the C23 function/allocator, as explained by Mr. Greg Barnlund in cross-examination with Mr. Antoine Hacault:

> MR. GREG BARNLUND: … So that the Industrial and Commercial Solutions Group perform functions directly with the general service large customers. So, that is our customer sales force or our marketing force that we have dealing directly with large volume customers in terms of the normal conduct of business operations between Manitoba Hydro and those customers.

> And so given that those staff are dealing directly with customers in those three (3) classes and, essentially, those three (3) classes exclusively, those costs are then allocated to those classes.
>
> MR. ANTOINE HACAULT: And for example, when there are new companies that are interested in coming, that marketing towards a new company is dealt with and paid for in that C-23 allocator; correct?
>
> MR. GREG BARNLUND: Well, to a certain extent. I mean there is other marketing activity I suppose that may be conducted even at the executive level for that matter that I'm -- that would not be captured in industrial and commercial solutions. When we're talking about the attraction of business to the province, that's a fairly broad subject to be dealing with.
>
> But certainly any involvement that would be -- and we would be assuming those customers would eventually fall into one (1) of the general service large classifications and so any staff that would be involved out of the Industrial and Commercial Solutions area are appropriately dealing with those particular business development opportunities. [T3214-3215]

To better understand this cost category and whether it is applicable to the GSL classes each subcategory is covered:

1. **Education & Safety ($1.2 million) and Rates & Regulatory ($3 million):** Education & Safety programs include safety around dams, waterways, substations, and overhead powerlines.[1] Rates & Regulatory relate to the work done in this department for such this as General Rate Applications, etc.

   MIPUG agrees that these services are beneficial to all customers and as such does not take issue with allocating a portion of these costs to GSL customers. Of note, the Revenue allocator, which allocates 6.2% of these costs to GSL 0-30kV, 4.8% to GSL 30-100kV and 12.5% to GSL >100kV (compared to the previous C10 allocator which respectively allocated 5.2% to 7.7%%)[2] the weighting of costs allocated to GSL >100kV customers has substantially grown without any known cost basis for increased cost causation.

   Regardless, MIPUG does not propose an alternative allocator for these specific costs at this time.

2. **Call Center - Outage Reports ($1.2 million):** Manitoba Hydro does not track contact center outages by customer class (Tr. page 3210) but does track by the

[1] MIPUG/MH I-11b

[2] Compared in Table 7-3 in MIPUG-13, page 7-8

nature of the call (billings, collections, outages, call before you dig)[3]. Hydro states that the contact center is the initial point of contact for all customers, and not specifically for customers served at the distribution level.[4] However, Hydro could not comment on if the GSL customers used the call center, and given the types of calls relate to types of services that for industrial customers are best answered by the Industrial & Customer Solutions services covered within C23 costs (i.e. by calling their customer representatives):

> MR. GREG BARNLUND: … The purpose of the contact centre and when we're talking about contact centre and outages and outage reporting, outage management, that is a function that is important overall to the overall operation of the system, and so it's not necessarily that you can be attributing it to specific customers as it is a more general function that serves the -- all customers across the system.
>
> MR. ANTOINE HACAULT: I understand that's Manitoba Hydro's view. But I'm trying to determine what the cause of this expense is. Who's calling.
>
> MR. GREG BARNLUND: Right.
>
> MR. ANTOINE HACAULT: And we know that there's $150,000 allocated to sixteen (16) customers purportedly with respect to outage calls?
>
> MR. GREG BARNLUND: Yes, sir. that's correct.
>
> MR. ANTOINE HACAULT: Do we have any idea whether there was even one (1) call from one (1) of those sixteen (16) customers to lead to that $150,000 expense that's being allocated to them?
>
> MR. GREG BARNLUND: I'm -- I don't have that information, no, sir. [T3210-3211]

To the extent the service would see at most limited use by the large industrial classes, it would not appear appropriate to allocate the costs to the GSL classes. If any allocation were merited, it should be based on unweighted customer numbers (i.e., notwithstanding their loads, each of an industrial customer and a residential customer would only phone once).

3. **Marketing R&D ($1.3 million):** This customer service activity includes creating marketing plans, customer surveys, maintaining customer coding databases, and

[3] MIPUG/MH I-11f

[4] MIPUG/MH I-11b

enhancing business development in the province.[5] Hydro states it's not specifically related to customers served at the distribution level, however no evidence was provided that these activities are not already provided to GSL customers within the Industrial & Customer Solutions department and was not aware of any GSL >100kV customers who use these services:

> MR. ANTOINE HACAULT: And my question is the same: Does Manitoba Hydro track marketing costs as it relates to general service large over 100? What marketing activities and R&D are specifically targeted at that group?
>
> MR. GREG BARNLUND: Again, that's a general category and if I could have the Information Request MIPUG/MH, round 2, 21 put on the screen that specifically addresses contact centre outages and marketing, R&D, and it provides further rationale that I'd like to speak to.
>
> MR. ANTOINE HACAULT: But dealing with my question, I'll let you answer that, do you have any data to show that there is a marketing exercise that's focused to the general service large over 100?
>
> MR. GREG BARNLUND: I'm not aware of any. [T3212]

Note that marketing to large customers is a specifically referenced activity of the C23: Industrial and Commercial Solutions group, which is entirely funded by industrial classes. As such, there would not appear to be any relevance to also charge GSL customers for marketing services to smaller customers through C10.

4. **Line Locates ($4.1 million):** Line locate services primarily relates to distribution facilities, based on the installed length of underground transmission lines compared to underground distribution. However, Manitoba Hydro suggests that the Line Locates category could include some activities related to locating transmission lines.[6]

   As Industrial and GSL customers do not use distribution assets, and in the absence of specific quantification as to the relevance of these services to transmission, it is reasonable that GSL customers should not be allocated these costs, let alone 24% of the costs (sum of C10 proposed allocation percentage to the 3 GSL classes in PCOSS18[7]).

[5] MIPUG/MH I-11b

[6] MIPUG/MH I-11c

[7] See MIPUG-13, Table 7-3 on page 7-8 for breakdown of allocation percentage

MR. ANTOINE HACAULT: And the description here indicates that the [line locates] service primarily relates to distribution? Do you see that?

MR. GREG BARNLUND: Yes, sir.

MR. ANTOINE HACAULT: That's an interesting adjective. What does "primarily" mean; 90 percent, 95 percent?

MR. GREG BARNLUND: Well, it's a generalization, because the nature of line locate activity varies with the level of construction activity in the province and is dependent upon that, so.

But I think it's safe to say that the majority of that work is related to distribution facilities.

MR. ANTOINE HACAULT: Now, we've used a different word, the "majority." Does Manitoba Hydro track whether there is any transmission lines underground for general service large that need to be line located in any particular year?

MR. GREG BARNLUND: It would be a very, very, very small occurrence if it were. I think that, typically speaking, I think that this is -- this particular cost category is one (1) that Manitoba Hydro is clear that is largely related to distribution.

And if a decision is made that those costs should be borne only by customers that are utilizing the distribution system, then that adjustment can be made in the cost of service study. I don't think that we're -- certainly not a hill to die on for Manitoba Hydro in that regard, Mr. Hacault.

MR. ANTOINE HACAULT: Would you know if there are any transmission or subtransmission lines serving the sixteen (16) general service large customers over 100 kV that are underground?

MR. GREG BARNLUND: I would doubt there are any.

MR. ANTOINE HACAULT: So the practical impact is that this class of general service large over 100, under this analysis, is being asked to pay $510,000 to locate lines that don't exist in the sense that there is none underground, they're all aboveground?

MR. GREG BARNLUND: Well, that's correct. I mean, I think that's the effect of what we're seeing here. [T3216-3218]

5. **Building Moves (60% of $3.1 million) and Safety Watches (40% of $3.1 million)[8]:** Building Moves relates to the costs not recovered directly by the particular customer for one Hydro representative to accompany movers and perform switching required to move buildings or structures. This work includes recoverable activities such as raising/lowering lines, rerouting lines and any time outside of normal working hours.[9] Safety Watches relates to the cost of a Manitoba Hydro employee to provide on-site safety watching for residential homeowner and contractors safety during work in close proximity to facilities.[10] In cross-exam, Mr. Barnlund clarified that safety watches could also relate to infrastructure related work undertaken by the provincial government and municipalities (including highway construction) and that some work will pertain to specific customers in the GSL category from time to time (Tr. pages 3226-3227). However Hydro could not provide comment on whether this infrastructure related work was related predominantly to distribution lines (which GSL >30kV customers do not use) and does not track these services by type of electric plant[11].

   Regarding Building Moves & Safety Watches, these services primarily relate to distribution facilities, but Hydro states they would also include transmission and subtransmission voltage facilities.[12] For Building moves:

   > MR. ANTOINE HACAULT: Out of the sixteen (16) general service large over 100 kV customers, how many of them have moved buildings which required the services described here?
   >
   > MR. GREG BARNLUND: I would say none of them. Let me explain what building moves are. Building moves are -- if you look at in Manitoba we have the ready-to-move building market. In other words, housing is built on -- off-site and it is transported down the highway to a customer's location where the new home is basically built or put on a new foundation.
   >
   > In order to facilitate those moves safely, Manitoba Hydro needs to undertake certain activities to raise the lines that cross the highways; in other words, our crews will go out and essentially lift power lines in certain locations to facilitate the transfer of these buildings as they're being trucked from one (1) location to another.

[8] MIPUG/MH I-11d
[9] MIPUG/MH I-11d
[10] MIPUG/MH I-11d
[11] MIPUG/MH I-11e
[12] MIPUG/MH I-11b

> There is no particularly one (1) customer class, if you would, that is causing them. It's the general activity associated with the economy that occurs and so it is a general activity that Manitoba Hydro needs to undertake to ensure that there is no contact with Manitoba Hydro's plant; that buildings are moved safely; that there is no outages that result from any kind of an incident.
>
> And so, it's a more general category of activity and it is, you know, in that regard then deemed to be allocated on the basis of revenue across all customer classes.
>
> And safety watches is a separate item but included in this category. Safety watches are where we need to be monitoring equipment as it is working underneath of our plant. And certainly when you think of highway interchanges that are being built in the province of Manitoba, they are not attributed to any particular customer class but it is the Department of Manitoba Infrastructure and Transportation that is requiring us to monitor activity underneath of these transmission lines.
>
> If a excavator is working underneath a transmission line and comes in -- too close of proximity to the conductor, there can be a flashover and there can be a serious incident. And so that's -- safety watching is our staff that is situated on site to be able to monitor the progress of construction and ensure that construction is being conducted in a safe manner.
>
> And so those costs are also captured in this category, and they are then determined to be allocated to all customer classes and the basis we've used is by customer class revenue. [T3218-3221]

The above excerpt does not address the issues raised in Mr. Bowman's pre-filed testimony (Exhibit MIPUG-13) at page 7-11 when he notes that Hydro claims to recover a large part of the costs of the building moves from the movers themselves, but then provides data that this revenue is not offsetting in the cost of service analysis:

> However, of the total $1.83 million expense, despite claims regarding cost recovery, Hydro notes that only $300 thousand[13] was collected as offsetting revenue[14] (and further, for some reason the revenue is not allocated at the same weightings as the expense, with residentials receiving a higher weighted allocation

[13] See transcript page 5998.
[14] MIPUG/MH II-8a-c

(47% of revenue) and GSL 30-100kV and GSL >100kV receiving a lower weighted allocation than the allocation used for the expenses (4% and 10% respectively).[15] Manitoba Hydro confirmed that the costs primarily relate to distribution lines.[16]

There are three possible ways to address the above issues:

1) Exclude the costs which do not relate to GSL from the GSL class cost allocation (potentially through redefining costs allocated to the C10 and C13 allocators).

2) Revise the Cost of Service study to include these costs in the distribution function rather than the customer service function. This would have the effect of making the classes who use that distribution system cover the costs of these services.

3) As an inferior approach, change the cost allocation of these categories to an "unweighted" customer allocation, so each customer on the system, regardless as to size, faces an equal share of the costs. This approach may be appropriate for the call center costs, for example, but would not appear to fit well with the line locate services or building moves which relate to distribution and should not have any allocation to customers which do not use those functions.

MIPUG recommends that Board adopt the first approach.

[15] MIPUG/MH II-8c
[16] MIPUG/MH I-11a-f page 4

ISSUE TOPIC #15:

ISSUE: RATE DESIGN

Should rate increases be applied across-the-board, i.e. equal amounts to all rate classes and all rates charged, or should there be differentiated rates to reflect the Revenue to Cost Coverage (RCC) ratios for customer classes that face rates well above costs?

Additionally regarding industrial rate design, should GSL classes have access to optional rates tied to the Time-Of-Use (TOU)?

MIPUG SUMMARY AND/OR RECOMMENDATION:

With respect to rate design, the PUB should use the PCOSS18 and the impacts of the 2016 Cost of Service Study review to set rates with positive movement towards the zone of reasonableness. In this respect, GSL 30-100kV, GSL >100kV and GSS Non Demand customers should all receive modestly lower than average rate increases for the 2018/19 year, to start to reduce the long-standing pattern of rates that exceed costs for these classes.

The PUB should direct Manitoba Hydro that rate options for customers are a priority, starting with an optional TOU rate. Following appropriate consultation with industrial customers, Manitoba Hydro should bring an optional TOU rate for approval to the PUB at the next General Rate Application.

DISCUSSION AND SUPPORT:

Customer Class Specific Rate Increases

The results of the PCOSS18 Cost of Service Study, including export revenues as an offset to class costs are shown in the Table below.

Revenue to Cost Comparison Calculation (with Comparison of Methods) from GSS-GSM/MH I-9

	(a) Total Cost ($000)	(b) Class Revenue ($000)	(c) Net Export Revenue ($000)	PCOSS18 RCC (b+c)/a	**Alternate RCC b/(a-c)**	RCC Change
Residential	810,916	607,106	161,911	94.8%	**93.5%**	-1.3%
GSS Non Demand	151,814	139,479	31,313	112.5%	**115.7%**	3.2%
GSS Demand	185,200	146,983	40,099	101.0%	**101.3%**	0.3%
GSM	253,466	191,737	57,472	98.3%	**97.8%**	-0.5%
GSL 0-30 kV	120,404	89,652	29,613	99.1%	**98.7%**	-0.4%
GSL 30-100 kV	86,975	69,995	25,054	109.3%	**113.0%**	3.7%
GSL >100 kV	230,688	180,458	70,042	108.6%	**112.3%**	3.7%
A&RL	22,987	21,571	1,482	100.3%	**100.3%**	0.0%

It is clear in the above analysis that, for example, the GSL >100 kV class faces rates $20 million above costs ($230 million in costs, less $70 million in export offsets totals $160 million in net costs, versus $180 million paid in rates). It is also clear that a ratio of 10% RCC would arise if the class paid $160 million, instead of $180 million. The issue is whether this $20 million should be compared to the $160 million in costs that the customers impose on the system to calculated the degree of overpayment ($20M/$160M = 12%) or to a hypothetical concept of “class revenue plus export revenue” of $250 million compared to class costs plus export costs of $230M ($20M/$230M = 9%). Mr. Bowman addressed this concept as follows:

> MR. PATRICK BOWMAN: … The other thing we comment on is the revenue to cost ratios and it -- I'm not sure about the debate over the measure of revenue cost coverages. I just know if I deal with a group of customers who are paying 180 million, and who have costs measured at 160 million, and the gap is 20 million, they would call that greater than 10 percent. 20 million out of 180 million of what they're paying is a greater than 10 percent gap.
>
> Now, Hydro may do some other math to tell them it's eight (8). I would suggest that we do it by the measures that would be relevant to customers, which is 20 million out of 180, and that's the essence of my submission on that point. [T6102]

Regardless, customers in three of the classes noted above are well outside the 95:105 RCC range, and when the RCC ratios are measured based on the MIPUG preferred approach of rates versus costs, are even outside a 90:110 range. As a result, rate adjustments are merited. Mr. Bowman addressed this comment in his direct examination as follows:

> MR. PATRICK BOWMAN: … Slide 45. I suggested in designing rates attention should be paid to the cost of service. I don't think it's an overriding consideration. I do work in jurisdictions where cost of service is an overriding factor, and it's far and away the biggest item considered is making sure that a cost of service ratio is at one hundred point zero zero (100.00) in each and every GRA. I don't think that's the way Manitoba should set rates, just like I don't think it's the way Manitoba should set a revenue requirement without looking at the long-term.
>
> I have a quote there, which is often frequently cited. It goes back to, it's quoted in Goodman, which is the lawyer's version of Bonbright, if I can put it that way, on utility rate-making from a case from the 1930s, but which emphasizes that the burden should be on the party who is trying to argue that rates shouldn't be based on costs. [T6102-6103]

The degree of adjustment required at the time should reflect 3 factors: 1) consistent with all aspects of rate setting for Hydro, any adjustment should reflect gradualism; 2) the rate adjustment should apply to customers outside the 95:105 zone of reasonableness. The zone of reasonableness has historically been set for 95% to 105% Revenue to Cost Comparison ratio since 1996 and has long been accepted as reasonable for purposes of rate setting in this jurisdiction[1]; and 3) the adjustment should be checked to ensure that it is not a temporary effect that will need to be reversed in the near-term, such as once Bipole III comes on line. Mr. Bowman addressed these points in his direct examination:

> MR. PATRICK BOWMAN: … I think the zone of reasonableness of 95:105 is appropriate for a large utility with a sophisticated cost of service study. I think examples of small utilities I've worked with, 90:110 or utilities whose cost of service studies have high degrees of uncertainty, or they don't have a very sophisticated approach, I don't -- we're not that type of utility.
>
> I think Bipole III will likely have the type of effect people are showing. In other words, if you -- it will have a tendency to put a larger cost in percentage terms on people who make more use of the bulk power system. I think that's a given, the way it's classified. So in cents per kilowatt hour basis, it'll cost a little more for residentials than industrials. But overall, people will tend to pay the same cents per kilowatt hour for Bipole. And as a result, the RCC ratios will pull in somewhat, but I don't -- it won't address the greater than 10 percent that we're facing.

[1] MIPUG-13, page 7-12.

> And so I think it's appropriate if you're going to have a cost of service study, to use it to make some adjustments. I also want to note that a zone of reasonableness is not a zone of excuse or a zone of negligence to say you're one at one-o- four-point-nine (104.9). You can stay there for twenty (20) years. It's meant to be variability about a hundred. It's not meant to be -- sit right at the edge and consider that as good as a hundred. [T6103-6104]

GSL 30-100kV, GSL >100kV and GSS Non-Demand should receive lower than average rate increases. MIPUG recommends a rate increase approximately 1 – 2 % lower than average. Note that this is consistent with a very slow 5-10 year plan to adjust rates towards unity (100% RCC), per PUB/MH-I-137a-b, as shown:

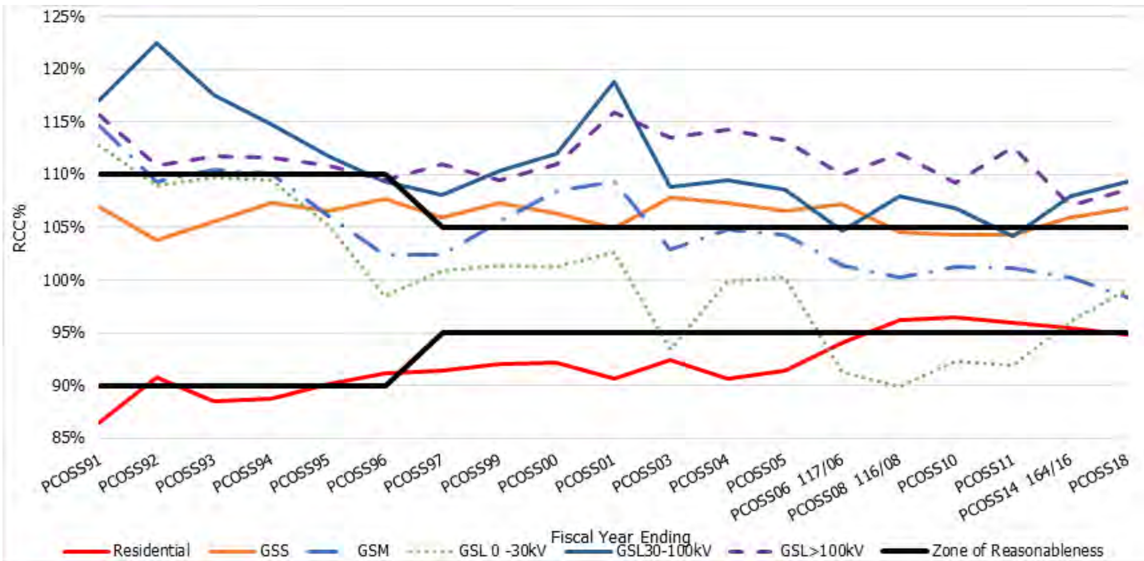
i. Achieve Unity (RCC's = 100%)

	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 10 Years	Final RCC
Residential	6.9%	1.3%	0.7%	100.0%
GSS Non Demand	-13.6%	-2.9%	-1.5%	100.0%
GSS Demand	-1.3%	-0.3%	-0.1%	100.0%
GSM	2.2%	0.4%	0.2%	100.0%
GSL 0-30kV	1.3%	0.3%	0.1%	100.0%
GSL 30-100kV	-11.5%	-2.4%	-1.2%	100.0%
GSL >100kV	-11.0%	-2.3%	-1.2%	100.0%
Area & Roadway Lighting	-0.3%	-0.1%	0.0%	100.0%

GSL customers specifically have been overpaying costs substantially outside of the zone of reasonableness for decades as shown in the table below (blue line for GSL 30-100kV and purple dashed for GSL >100kV). Note that for 2017/18 this totals almost $30 million more than the cost to serve between the 2 classes[2].

[2] From RCC Calculation Table above - $20 million for GSL >100kV ($180 million revenue less $230 million in costs less $70 million net export revenue) and $9 million for GSL 30-100kV ($70 million revenue less $87 million in costs less $25 million net export revenue).

**Revenue to Cost Comparison Ratios
(MIPUG-27)**



Manitoba Hydro has stated that with respect to Bipole III costs, this will have the effect of narrowing the measured customer RCC ratios. However, even with such narrowing, the RCC ratios still show room for the rate adjustments of 1-2 percentage points as proposed by MIPUG, as follows (per Exhibit MH-88, page 16):

Customer Class	PCOSS18 (as filed)	Estimated Revenue Cost Coverage in 2020 with BPIII In Service	
Residential	94.8%	96.7%	Increase
GSS Non Demand	112.5%	115.3%	Increase
GSS Demand	101.0%	101.3%	Neutral
GSM	98.3%	97.4%	Decrease
GSL 0-30 kV	99.1%	96.5%	Decrease
GSL 30-100 kV	109.3%	103.5%	Decrease
GSL >100 kV	108.6%	101.5%	Decrease
A&RL	100.3%	118.2%	Increase

As shown above, even if 1-2% decreases (and hence lower RCC ratios) were implemented for the three noted classes, each would still be near or above 100%. In short, there is no evidence that a 1-2% rate adjustment today has any likelihood of requiring reversal in future. Also, as noted by Mr. Bowman, the impacts of Bipole may prove to be different and more muted than expected:

> MR. PATRICK BOWMAN: … By the way, there was also claims made at one point that Wuskwatim was going to do the same thing, that Wuskwatim would take care of our revenue cost coverage problem for industrials, because it was going to do the same thing as everyone says Bipole and Keeyask will do. And clearly they did not, so. [T6105]

Finally, Mr. Bowman addressed the issue of the revenue to Hydro, noting that lowering the industrial rate increase by 1-2% below average would have relatively modest impacts on Hydro's overall revenue:

> MR. PATRICK BOWMAN: … So my suggestion is there is a room to give a lower than average rate increase to the classes who are above that would apply to the GSL 30-100 and greater than a hundred. It would also apply to one (1) of the GS small classes. I'm not saying dramatic moves like 10 percent. We're talking 1 to 2. It's a difference of about 2.2 to 4.4 million in Hydro's revenue. [T6104]

In short, with a now finalized cost-of-service study (PCOSS18), if the results are to have any normal meaning consistent with fairness and normal principles applied to utility regulation, the RCC ratios must begin to be used to implement a principles rate adjustment for classes that are paying rates clearly above costs, and even above the longstanding zone of reasonableness.

Optional Time-Of-Use (TOU) Rates

In the 2016 Cost of Service Study review, Manitoba Hydro proposed and the PUB accepted that TOU rates would be dealt with at the next GRA (i.e. this GRA). However, Hydro has chosen not to advance a proposal for TOU rates at this point in time largely due to the impact the rate design change would have on some customers combined with the magnitude of the rate increases Hydro is seeking for 2017/18. [T2414-2416]

MIPUG agrees that implementing a mandatory TOU rate for all customers is not appropriate, given the rates would have likely negative impacts for GSL customers that are unable to shift load usage at peak times (i.e. customers who have fixed processes or high load factor usage levels in that they run their processes at the same level all the time). TOU rates are based on economic incentive, as explained by Mr. Barnlund:

> MR. GREG BARNLUND: Well, we're really in a time of use rate, looking at structuring our rate, which places greater emphasis on the energy component of the charge, and differentiates that energy component from on-peak to off-peak. Demand charges are sort of an outcome of it. Like, we would have to address the existence of demand charges, but there are time of use rates which have minimal demand charges, and most of the cost recovered through the energy charge.

> MS. DAYNA STEINFELD: And so at a high level, it -- the principle is that customers would shift consumption to off-peak times when there's a lower energy cost?

> MR. GREG BARNLUND: Yes, they'd have an economic incentive to do so. [T2460]

The economic incentive is market based in distinguishing between on peak and off-peak energy usage:

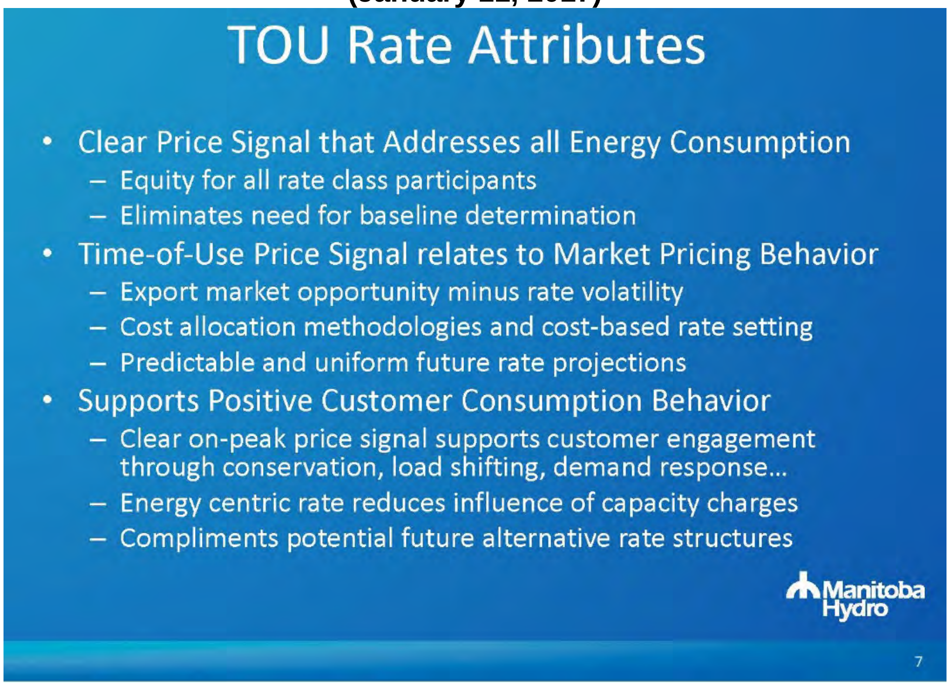
> MR. GREG BARNLUND: Well, it's relevant to the type of market we have across the border in the MISO system, where we are transacting sales in an on-peak and in off-peak hours. And so the design of this rate structure is to more or less emulate that structure, if you would, of on-peak and off-peak, with the idea that you're being more reflective, I think, of sort of the market conditions or the market dynamic pricing that you would see in a MISO market, day-ahead market, and reflecting that more or less to a certain extent in your rate design, as opposed to our very flat rate that we currently have right now.

> MS. DAYNA STEINFELD: And so is it -- and is it fair to say that an on-peak hour is when energy would have the highest value on the export market?

> MR. GREG BARNLUND: Certainly it's going to have higher value on-peak than it would off-peak, yes. [T2462-2463]

Other attributes of TOU rates are described by Manitoba Hydro:

Hydro TOU Presentation as provided in MIPUG/MH I-5a-f-Attachment (January 11, 2017)



Large customers require rate/program options to manage their electricity bills to remain competitive. There are some customers who would benefit from TOU rates as was stated in the presentation of Mr. Darren MacDonald from Gerdau:

> MR. DARREN MACDONALD: ... The Manitoba facility is the only one that we have in North America that does not have an opportunity to manage its cost using a curtailable rate. We have demand response opportunities -- a whole host of them. We have interruptible contracts. We have some way to manage our costs or get credit for our ability to interrupt in every jurisdiction we operate in North America except here. So that's a significant difference and it leaves us with no way to control our costs.
>
> The time-of-use rates was a proposal that we supported and were very interested in. I know that Manitoba Hydro worked hard on that, got it Board approved but was never implemented.
>
> And incentive rates. I can tell you there's jurisdictions that we operate in and I gave an example here in TVA, Tennessee Valley, there's a Valley investment initiative that provides an economic incentive based on your FTEs, full-time equivalents; the Capex that you put into your plant; how much electricity consume; all of those are go into their black box, but they

> provide you a significant reduction in your electricity bill for operating and making investments in their jurisdiction. [T7733-7734]

The potential system-wide benefits of a time-of-use option were reviewed with Mr. Barnlund under cross-examination:

> MR. ANTOINE HACAULT: Thank you for 4 that clarification. I'll move on to a different subject, time of use rates. … Probably they are questions that Mr. Barnlund can answer or deal with.
>
> Would you agree, Mr. Barnlund, that there would be overall system benefits in terms of peak load shifting if the industrial class was able to adjust production schedules, et cetera?
>
> MR. GREG BARNLUND: Generally, I would agree with that. I think that the important aspect to consider is the degree to which load could be shifted, and therefore, that would affect or influence the amount of benefit that the system may receive. [Tr: 3177]

Regarding potential lost revenues to Hydro of a potential TOU rate structure (from PUB-MIPUG-5):

> There is a known cost implication to the system from using more power at off peak times than at on peak, even on days where the system is not at an absolute system demand peak (e.g., one of the 50 highest peaks in the Cost of Service study). So a customer whose load profile is favourable compared to the class average (e.g., a customer that sees somewhat more energy use at night, or on weekends, or in shoulder seasons) would see a slightly lower cost under a time of use structure.
>
> Offering this customer a time of use structure, and correspondingly a slightly lower revenue for the utility, is recognition of this lower cost profile.
>
> Ultimately, in the example cited, if no load shifting occurs, the class costs in the COS study will not change, but the class revenue will drop a small amount. This will not directly affect any of the other classes, it will only show up as a reduction in the GS Large RCC ratio. If the revenue drop is large enough to drop the GS Large RCC ratio below 100%, then the difference should be made up by higher than average increases to the class. This will, in effect, lead to slightly higher costs to the customers who do not have advantageous load profiles, as would be intended.

> At the present time, it is acknowledged that implementing a TOU option for industrial customers would slightly reduce Hydro's revenue. However, the industrial class is paying rates above costs by almost $20 million for >100 kV and $8 million for 30-100 kV (see Table 7-1 from MIPUG-13). To the extent that the Board concludes that Hydro does not require the full 7.9% proposed, this type of relief should be the first priority for implementing net increases lower than 7.9% (also the GSS Small Non-Demand class at 115.7%, of $19 million above cost).

More detail was provided by Patrick Bowman in direct examination:

> MR. PATRICK BOWMAN: ... On the issue of optional time of use rates, I have been suggesting for some time and the members have echoed in my -- to me the importance of industrials having some options for how they manage their costs. Many if not most jurisdictions, if you walk into sign up for service, you have more than one (1) option. Even here if you looking for service, you have more than one (1) option. There's another rate called a limited use of billing demand. You will make your decision based on your expected load profile.
>
> I'm suggesting one (1) more is needed, which is a time of use one (1). It doesn't have to be a rate design imposed on everyone. It could be done on an optional basis. And that I don't -- what we've seen to date is Hydro is loathe to go down the road of optional. As an example, BC Hydro has an optional time of use versus the -- versus a base one (1). It's poorly designed and not a lot of people use it, but it is an option.
>
> The problem, of course, is that Hydro hasn't brought forward a rate design, and the proper way to design rates is with an eye to both embedded costs in terms of a fairness sense, but also marginal cost in terms of a rate design sense. And since our marginal cost have changed so much, I think it's acceptable for Hydro to say, I haven't thought through quite how I would do it, even though a couple of years ago they had a proposal.
>
> I would only emphasize one (1) point that seemed to be the theme of a number of the Board's IRs, which is how do time of use rates help anyone if no one shifts load. And my submission is time of use rates help make the rates within a class fairer, even if customers don't shift load.
>
> If customers can shift load they can bring benefits to the entire system. If a customer can bump some of its load from on peak hours when Hydro can get a good price to off-peak hours when Hydro can't, even if it's not a

> lot of load, that's a net benefit to the system. It will improve our export prices. It'll improve Hydro's flexibility. And I -- and it could be a way that a customer could help manage their bill increases or cut their costs. So it's an upside of a time of use design. It's not central to a time of use design. You don't require load shifting to be able to come up with a time of use design. [T6105-6107]

Especially in an environment where Manitoba Hydro's rates are not as competitive as previously experienced in this jurisdiction by industrial customers, Manitoba Hydro has to prioritize competitive rate options for industrial customers to remain operating in Manitoba.

Note that this is also consistent with the direction from the Minister as noted in the Minister's letter to Hydro setting out the Manitoba Government's response to the NFAT report (produced as part of Exhibit MH#45 in the 2015/16 GRA), as follows:

> The NFAT review has also raised the unique needs of large industrial power users. In response we request that Manitoba Hydro advance measures such as curtailable rates and load displacement programs which meet the needs of large power users like manufacturers and resources industries that create jobs and grow our Province's economy.[3]

The recommendation of Mr. Bowman as stated in cross-examination with PUB counsel is echoed by MIPUG as follows:

> MR. PATRICK BOWMAN: My suggestion to the Board is that it indicate to Hydro that work should be done on an -- creating a new rate schedule available to at least the largest two (2) classes of customers. And that that rate schedule should be one (1) that customers can opt into, but need not be required to move into. That rate schedule would not change the fact that they're in the overall class for the purpose of setting RCCs, so if there is less revenue it would affect the -- it would affect the class in the cost of service study.
>
> And that as part of that design they should consider marginal cost, so that they can design a rate that gives customers more recognition of their ability to use off-peak power at lower prices and to cut back their use of on peak power if possible and receive a greater bill benefit from doing so.
>
> MS. DAYNA STEINFELD: And is the timeline for completion of the analysis that you suggest the next General Rate Application?

[3] Exhibit MH#45 in the 2015/16 GRA, page 5

MR. PATRICK BOWMAN: I think that's practical. I'd only say that as long as that provides enough time for consultation with customers that -- which would be a normal part of looking at a rate design like this. It's not like you have a hundred thousand customers to consult with. So as long as it had -- provided time for that, the General Rate Application is appropriate. [T6458-6459]

MIPUG FINAL ARGUMENT

2017/18 & 2018/19 Manitoba Hydro General Rate Application

ATTACHMENT

A) NFAT Review Final Argument of Manitoba Hydro, pages iv, v and vi from the index (Exhibit 204).

B) ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission), 2015 SCC 45.

C) Nova Scotia Utility and Review Board, Nova Scotia Power Inc., Re, 2011 CarswellNS 831, 2011 NSUARB 184.

D) Advocacy Centre for Tenants-Ontario v. Ontario (Energy Board), 2008 CarswellOnt 2830, [2008] O.J. No. 1970, 166 A.C.W.S. (3d) 384, 238 O.A.C. 343, 293 D.L.R. (4th) 684.

E) Brandon Transit Consumers Assn. Inc. v. Brandon (City), 1985 CarswellMan 74, 18 D.L.R. (4th) 459, 30 M.P.L.R. 78, 32 A.C.W.S. (2d) 309, 34 Man. R. (2d) 36.

F) Goodman, L. S.: The Process of Ratemaking: 1998: Public Utilities Reports Inc. Vienna, Virginia; vol. 1 at pages 17-19, 130, 279-281. (Includes citation to Shell Oil Co. v. F.P.C. 52 F. 2d 1061 at pp. 1083-84 (5th Cir 1975) – Page 280).

G) Citation from Energy Law Journal, page 306, footnote 14: Elmira Water, Light & R.R., 1922 D Pub. Util. Rep. (PUR) 231, 238.

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MANITOBA PUBLIC UTILITIES BOARD

IN THE MATTER OF *Order in Council 128/2013 and attached Terms of Reference Needs For and Alternatives (NFAT) Review*

AND IN THE MATTER OF *Manitoba Hydro's Filing with Respect to the Need For and Alternatives to Manitoba Hydro's Preferred Development Plan*

FINAL ARGUMENT

OF MANITOBA HYDRO

May 26, 2014

Manitoba Hydro

SUPREME COURT OF CANADA

CITATION: ATCO Gas and Pipelines Ltd. *v.* Alberta (Utilities Commission), 2015 SCC 45

DATE: 20150925
DOCKET: 35624

BETWEEN:

ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.
Appellants
and
Alberta Utilities Commission and
Office of the Utilities Consumer Advocate of Alberta
Respondents

CORAM: McLachlin C.J. and Abella, Rothstein, Cromwell, Moldaver, Karakatsanis and Gascon JJ.

REASONS FOR JUDGMENT: (paras. 1 to 66)	Rothstein J. (McLachlin C.J. and Abella, Cromwell, Moldaver, Karakatsanis and Gascon JJ. concurring)

NOTE: This document is subject to editorial revision before its reproduction in final form in the *Canada Supreme Court Reports*.

ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. *Appellants*

v.

Alberta Utilities Commission and Office of the Utilities Consumer Advocate of Alberta *Respondents*

Indexed as: ATCO Gas and Pipelines Ltd. *v.* Alberta (Utilities Commission)

2015 SCC 45

File No.: 35624.

2014: December 3; 2015: September 25.

Present: McLachlin C.J. and Abella, Rothstein, Cromwell, Moldaver, Karakatsanis and Gascon JJ.

ON APPEAL FROM THE COURT OF APPEAL FOR ALBERTA

Public utilities — Gas — Electricity — Rate-setting decision by utilities regulator — Utilities seeking to recover pension costs in utility rates set by Alberta Utilities Commission — Whether regulatory framework prescribes certain methodology in assessing whether costs are prudent — Whether Commission's *interpretation and exercise of its rate-setting authority was reasonable — Electric Utilities Act, S.A. 2003, c. E-5.1, ss. 102, 121 and 122 — Gas Utilities Act, R.S.A. 2000, c. G-5, s. 36.*

The Alberta Utilities Commission denied the request by ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. ("ATCO Utilities") to recover, in approved rates, certain pension costs related to an annual cost of living adjustment ("COLA") for 2012. Instead of approving recovery for an adjustment of 100 percent of annual consumer price index ("CPI") (up to a maximum COLA of 3 percent), the Commission ruled that recovery of only 50 percent of annual CPI was reasonable. The Alberta Court of Appeal dismissed the ATCO Utilities' appeal from the decision of the Commission.

Held: The appeal should be dismissed.

A key principle in Canadian regulatory law is that a regulated utility must have the opportunity to recover its operating and capital costs through rates. This requirement is reflected in the *Electric Utilities Act* and the *Gas Utilities Act* of Alberta, as these statutes refer to a reasonable opportunity to recover costs and expenses so long as they are prudent. The Commission must therefore determine whether a utility's costs warrant recovery on the basis of their reasonableness — or, under the *Electric Utilities Act* and the *Gas Utilities Act*, their "prudence". Where costs are determined to be prudent, the Commission must allow the opportunity to recover them through rates.

The prudence requirement is to be understood in the sense of the ordinary meaning of the word: for the listed costs and expenses to warrant a reasonable opportunity of recovery, they must be wise or sound; in other words, they must be reasonable. Nothing in the ordinary meaning of the word "prudent" or the use of this word in the statute as a stand-alone condition says anything about the time at which prudence must be evaluated. Thus, neither the ordinary meaning of "prudent" nor the statutory language indicate that the Commission is bound by the legislative provisions to apply a no-hindsight approach to the costs at issue, nor is a presumption of prudence statutorily imposed in these circumstances. In the context of utilities regulation, there is no difference between the ordinary meaning of a "prudent" cost and a cost that could be said to be reasonable. It would not be imprudent to incur a reasonable cost, nor would it be prudent to incur an unreasonable cost. Further, the burden of establishing that the proposed tariffs are just and reasonable falls on public utilities, which necessarily imposes on them the burden of establishing that the costs are prudent. The impact of increased rates on consumers cannot be used as a basis to disallow recovery of such costs. This is not to say that the Commission is not required to consider consumer interests. These interests are accounted for in rate regulation by limiting a utility's recovery to what it reasonably or prudently costs to efficiently provide the utility service. That is, the regulatory body ensures that consumers only pay for what is reasonably necessary.

ONUS:

Though the *Electric Utilities Act* and the *Gas Utilities Act* do contain language allowing for the recovery of "prudent" costs, the statutes do not explicitly impose an obligation on the Commission to conduct its analysis using a particular methodology any time the word "prudent" is used. Thus, the Commission is free to apply its expertise to determine whether costs are prudent (in the ordinary sense of whether they are reasonable), and it has the discretion to consider a variety of analytical tools and evidence in making that determination so long as the ultimate rates that it sets are just and reasonable to both consumers and the utility.

The standard of review of the Commission's decision in applying its expertise to set rates and approve payment amounts is reasonableness. Under this standard of review, the Commission's interpretation of its home statute is entitled to deference. In this case, it was not unreasonable for the Commission to decide, without applying a no-hindsight analysis, that 50 percent of CPI (up to a maximum COLA of 3 percent) represented a reasonable level for setting the COLA amount for the purposes of determining the pension cost amounts for regulatory purposes: the Commission was not statutorily bound to apply a particular methodology to the costs at issue in this case; the use of the word "prudent" in the *Electric Utilities Act* and the *Gas Utilities Act* cannot by itself be read to impose upon the Commission a specific no-hindsight methodology; and the disallowed costs were forecast costs. Accordingly, it was reasonable for the Commission to evaluate the ATCO Utilities' proposed revenue requirement in light of all relevant circumstances. Further, because the Commission did not use impermissible methodology, it was not unreasonable for the Commission to direct the ATCO Utilities to reduce their pension costs incorporated into revenue requirements by restricting the annual cost of living adjustment.

Cases Cited

Referred to: *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44; *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186; *Dunsmuir v. New Brunswick*, 2008 SCC 9, [2008] 1 S.C.R. 190; *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140; *Shaw v. Alberta Utilities Commission*, 2012 ABCA 378, 539 A.R. 315; *ATCO Gas and Pipelines Ltd. v. Alberta Utilities Commission*, 2009 ABCA 246, 464 A.R. 275; *Alberta (Information and Privacy Commissioner) v. Alberta Teachers' Association*, 2011 SCC 61, [2011] 3 S.C.R. 654; *Power Workers' Union, Canadian Union of Public Employees, Local 1000 v. Ontario Energy Board*, 2013 ONCA 359, 116 O.R. (3d) 793; *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (2006), 210 O.A.C. 4; *McLean v. British Columbia (Securities Commission)*, 2013 SCC 67, [2013] 3 S.C.R. 895; *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27; *TransCanada Pipelines Ltd. v. National Energy Board*, 2004 FCA 149, 319 N.R. 171.

Statutes and Regulations Cited

Electric Utilities Act, S.A. 2003, c. E-5.1, ss. 102, 121, 122.

Employment Pension Plans Act, R.S.A. 2000, c. E-8, ss. 13, 14, 48(3).

Employment Pension Plans Act, S.A. 2012, c. E-8.1, ss. 13, 35(2), 52(2)(b).

Employment Pension Plans Regulation, Alta. Reg. 35/2000, ss. 9, 10, 48(3).

Employment Pension Plans Regulation, Alta. Reg. 154/2014, ss. 48, 49, 60(2)(b), (3).

Gas Utilities Act, R.S.A. 2000, c. G-5, ss. 36, 37(3), 44(1), (3).

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sch. B.

Roles, Relationships and Responsibilities Regulation, Alta. Reg. 186/2003, s. 4(3).

Authors Cited

Concise Oxford English Dictionary, 12th ed., by Angus Stevenson and Maurice Waite, eds. Oxford: Oxford University Press, 2011, "prudent".

Driedger, Elmer A. *Construction of Statutes*, 2nd ed. Toronto: Butterworths, 1983.

Merriam-Webster's Collegiate Dictionary, 11th ed. Springfield, Mass.: Merriam-Webster, 2003, "prudent".

Oxford English Dictionary, 2nd ed. Oxford: Clarendon Press, 1989, "prudent".

Reid, Laurie, and John Todd. "New Developments in Rate Design for Electricity Distributors", in Gordon Kaiser and Bob Heggie, eds., *Energy Law and Policy*. Toronto: Carswell, 2011, 519.

APPEAL from a judgment of the Alberta Court of Appeal (Costigan, Martin and Slatter JJ.A.), 2013 ABCA 310, 93 Alta. L.R. (5th) 234, 556 A.R. 376, 7 C.C.P.B. (2d) 171, 584 W.A.C. 376, [2013] A.J. No. 989 (QL), 2013 CarswellAlta 1984 (WL Can.), affirming a decision of the Alberta Utilities Commission, 2011 CarswellAlta 1646 (WL Can.), [2011] A.E.U.B.D. No. 506 (QL). Appeal dismissed.

John N. Craig, Q.C., Loyola G. Keough and *E. Bruce Mellett*, for the appellants.

Catherine M. Wall and *Brian C. McNulty*, for the respondent the Alberta Utilities Commission.

Todd A. Shipley, *C. Randall McCreary*, *Michael Sobkin* and *Breanne Schwanak*, for the respondent the Office of the Utilities Consumer Advocate of Alberta.

The judgment of the Court was delivered by

ROTHSTEIN J. —

[1] In its decision of September 27, 2011, the Alberta Utilities Commission denied the request by ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. (collectively the "ATCO Utilities") to recover, in approved rates, certain pension costs related to an annual cost of living adjustment ("COLA") for 2012. Instead of approving recovery for an adjustment of 100 percent of the annual consumer price index ("CPI") (up to a maximum COLA of 3 percent), the Commission ruled that recovery of only 50 percent of annual CPI (up to a maximum COLA of 3 percent) was reasonable. The Alberta Court of Appeal dismissed the ATCO Utilities' appeal from the decision of the Commission. The ATCO Utilities now appeal to this Court.

[2] This matter was heard together with *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 ("*OEB*"), which also concerns the review of a rate-setting decision by a utilities regulator. Although the facts of the cases are different, both involve issues of methodology, and, in particular, when — if ever — a

regulator is required to apply a particular regulatory tool known as the "prudent investment test" in assessing a utility's costs.

[3] The ATCO Utilities submit that the Commission is bound to first assess costs put forward by a utility for prudence, and that prudently incurred costs must be approved for inclusion in the utility's "revenue requirement". This term refers to "the total revenue that is required by the company to pay all of its allowable expenses and also to recover all costs associated with its invested capital": L. Reid and J. Todd, "New Developments in Rate Design for Electricity Distributors", in G. Kaiser and B. Heggie, eds., *Energy Law and Policy* (2011), 519, at p.521. The approved revenue requirement is then to be allocated to customers in the form of just and reasonable rates. The ATCO Utilities argue that the Commission failed to properly address the prudence of such costs. They say that in the absence of an explicit contrary finding, costs are presumed to be prudent. Further, the Utilities assert that prudence is to be established based on circumstances as of the date of the cost decision — not based on hindsight and the use of information not available to the utility when the decision to incur the cost was made.

[4] The Office of the Utilities Consumer Advocate of Alberta argues that the Alberta regulatory framework does not impose a specific rate-setting methodology on the Commission; it falls to the Commission to decide upon the specific test and methodology to employ. Specifically, the Consumer Advocate argues that there is no obligation on the Commission to utilize a particular prudence test methodology when

reviewing costs on a forecast basis. Nor is there a presumption of prudence. On the contrary, the onus is on the utility to demonstrate that the tariff it proposes is just and reasonable.

[5] As in *OEB*, the relevant statutory framework does not impose upon the Commission the "prudence" methodology urged by the ATCO Utilities. Further, following the approach set out in *OEB*, the methodology adopted by the Commission and its application of this methodology were reasonable in view of the nature of the costs in question. I would dismiss the appeal.

I. Regulatory Framework

[6] In Alberta, the Commission sets "just and reasonable" tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses: s. 121(2)(a) of the *Electric Utilities Act*, S.A. 2003, c. E-5.1 ("*EUA*"); and s. 36(a) of the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("*GUA*").

[7] In Canadian law, "just and reasonable" rates or tariffs are those that are fair to both consumers and the utility: *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186, at pp. 192-93, per Lamont J. Under a cost of service model, rates must allow the utility the opportunity to recover, over the long run, its operating and capital costs. Recovering these costs ensures that the utility can continue to operate and can earn its cost of capital in order to attract and retain investment in the utility: *OEB*, at para. 16. Consumers must pay what the

Commission "expects it to cost to efficiently provide the services they receive" such that, "overall, they are paying no more than what is necessary for the service they receive": *OEB*, at para. 20.

II. Facts

A. *The Pension Plan*

[8] Employees of the ATCO Utilities benefit from the Retirement Plan for Employees of Canadian Utilities Limited ("CUL", the parent company of the ATCO Utilities) and Participating Companies (the "Pension Plan"). The Pension Plan is administered by CUL, which is not itself regulated by the Commission. As the Pension Plan administrator, CUL acts in a fiduciary capacity in relation to Plan members and other Plan beneficiaries: s. 13(5) of the *Employment Pension Plans Act*, R.S.A. 2000, c. E-8.[1]

[9] The Pension Plan includes a defined benefit plan (the "DB plan"), which was closed to new employees on January 1, 1997, and a defined contribution plan. The COLA applies only to the DB plan. The *Employment Pension Plans Act* requires that the DB plan be subject to actuarial calculations filed periodically with the Superintendent of Pensions for Alberta: ss. 13 and 14;[2] and ss. 9 and 10 of the

[1] This provision has since been replaced by s. 35(2) of the *Employment Pension Plans Act*, S.A. 2012, c. E-8.1.
[2] These provisions have since been replaced by s. 13 of the *Employment Pension Plans Act*, (2012).

2011 NSUARB 184
Nova Scotia Utility and Review Board

Nova Scotia Power Inc., Re

2011 CarswellNS 831, 2011 NSUARB 184

In the Matter of the Public Utilities Act

In the Matter of an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

In the Matter of an Application by NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Limited for Approval of amendments to Nova Scotia Power Incorporated's Load Retention Tariff and for a Load Retention Rate effective January 1, 2012

Kulvinder S. Dhillon Member, Peter W. Gurnham Chair, Roland A. Deveau Acting V-Chair

Heard: September 19 - October 27, 2011
Judgment: November 29, 2011
Docket: NSUARB-NSPI-P-892, NSPI-P-202

Counsel: Rene Gallant, Terry Dalgleish, Q.C., Nicole Godbout, Colin Clarke, for Nova Scotia Power Incoporated
David S. MacDougall, James MacDuff, for Newpage Port Hawkesbury Corp., Bowater Mersey Paper Company Limited
Nancy G. Rubin, Maggie A. Stewart, for Avon Group
John P. Merrick, Q.C., William L. Mahody, for Consumer Advocate
E.A. Nelson Blackburn, Q.C., Joseph M.J. Cooper, Q.C., Paul B. Miller, for Small Business Advocate
Stephan Jedynak, Angus Doyle, Julian Boyle, for Halifax Regional Municipality
Stephen McNeil, Shawn Lawlor, for Liberal Caucus Office
Al Dominie, for Municipal Electric Utilities of Nova Scotia Co-operative
Chuck Porter, Jennifer Edge, Sarah Reeves, for Progressive Conservative Caucus Office
Stephen T. McGrath, Ryan Brothers, for Province of Nova Scotia (Departments of Energy, Environment and Natural Resources)
S. Bruce Outhouse, Q.C., for Board

Subject: Public

Headnote

Public law --- Public utilities — Operation of utility — Rates — Fairness and impartiality

Public law --- Public utilities — Operation of utility — Rates — Miscellaneous

Public law --- Public utilities — Regulatory boards — Practice and procedure — Miscellaneous

Table of Authorities

Statutes considered:

Bankruptcy Code, 11 U.S.C. 1982
Chapter 11 — referred to

Companies' Creditors Arrangement Act, R.S.C. 1985, c. C-36
Generally — referred to

Public Utilities Act, R.S.N.S. 1989, c. 380
Generally — referred to

s. 52 — referred to

s. 64 — referred to

s. 67(1) — referred to

s. 86 — referred to

s. 87(1) — referred to

s. 109(1) — referred to

Decision of the Board:

1.0 Introduction

1 This Decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the "Board") on September 19, 21, 22 and October 24 - 27, 2011, in the matter

of an application by Nova Scotia Power Incorporated ("NSPI", the "Company", the "Utility"), dated May 13, 2011, for approval of revisions to its Rates, Charges and Regulations (the "NSPI Application") and an application dated June 22, 2011, by NewPage Port Hawkesbury Corp. ("NewPage") and Bowater Mersey Paper Company Limited ("Bowater") (collectively known as "NPB") for amendments to the Load Retention Tariff ("LRT") and a Load Retention Rate ("LRR") (the "NPB Application").

2 NSPI is engaged in the production and supply of electrical energy. It distributes electricity through a province-wide system and, as at December 31, 2010, served approximately 489,000 customers, including six municipal electric utilities.

3 In its Application, NSPI requested an increase in rates in order to meet its estimated revenue requirement increase for 2012 of $94.4 Million. NSPI used 2012 estimated costs as a 'test year' for the purpose of determining the additional revenue it required and the corresponding rate increases for its various customer classes, should its Application be approved. The proposed overall average rate increase was 7.3%, with certain customer classes subject to a higher or lower rate increase. The average residential customer would see a 7.1% increase with increases ranging from 5.5% to 13.5% for all other metered classes of customers.

4 The NPB Application requested amendments to the terms and conditions of NSPI's existing LRT. These proposed revisions would extend the applicability of this LRT to instances where there is an impending business closure due to the economic distress of NSPI's largest customers (i.e., NewPage and/or Bowater). Further, NPB proposed a new pricing mechanism that would result in a new LRR. The new rate is proposed to be in effect for five years, up to and including 2016.

5 If approved, the proposed LRR would result in a further increase to electricity rates for NSPI's other customer classes. For example, if both applications of NSPI and NPB were approved by the Board, the average residential customer would see a 9.4% increase (compared to a proposed 7.1% increase under NSPI's application). For all other metered classes of customers, the increases would range from 8.4% to 9.6% if the applications of both NSPI and NPB are approved.

6 The Board determined that both applications would be heard concurrently and that the Intervenors in NSPI's Application would be recognized as Intervenors in NPB's Application.

7 The public hearing was duly advertised in accordance with sections 64 and 86 of the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended (the "*Act*"), which read as follows;

Approval of schedule of rates and charges of utility

64(1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

Filing with Board

(2) The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act R.S., c. 380, s. 64.

Notice of hearing of application for rate changes

86 Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board. R.S., c. 380, s. 86.

8 A total of 20 formal Intervenors responded to the applications of NSPI and NPB. A number of these parties were represented at the hearing by counsel. The Nova Scotia Department of Energy, Department of Environment, and Department of Natural Resources (the "Province"); the Small Business Advocate ("SBA"); the Consumer Advocate ("CA"); Avon Group ("Avon"), whose counsel represented 14 Intervenors; NPB; Halifax Regional Municipality ("HRM"); the Liberal Caucus Office; the Progressive Conservative Caucus Office; and the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC") all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI's Application and both opposing and supporting NPB's Application.

9 On August 22, 2011, NSPI's largest customer, NewPage, announced an indefinite shut down of its Port Hawkesbury operations. In early September, NewPage filed and obtained creditor protection under the federal *Companies' Creditors and Arrangement Act*. NewPage's parent company, NewPage Corporation, and certain of its other U.S. based subsidiaries, have filed for bankruptcy protection in the U.S. under Chapter 11 of the *United States Bankruptcy Code*. During the public hearing, the Board was advised of a Court approved process to find a purchaser for the NewPage plant in Port Hawkesbury.

2.0 Background

10 NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual

monopoly on electricity service throughout the province. It is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the province. The Board regulates NSPI in the public interest on a cost of service basis. The *Act* gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. In addition to statutory requirements to be considered during a general rate application, the Board is also guided by long-established, fundamental ratemaking principles. In its Decision dated March 31, 2005, on a rate application by NSPI, the Board explained these guidelines as follows:

> In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates,** sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
>
> 2. Freedom from controversies as to proper interpretation.
>
> 3. Effectiveness in yielding total revenue requirements under the fair-return standard.
>
> 4. Revenue stability from year to year.
>
> 5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
>
> 6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
>
> 7. Avoidance of "undue discrimination" in rate relationships.
>
> 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
>
> (a) in the control of the total amounts of service supplied by the company;

(b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

[Board Decision, March 31, 2005, p. 14]

11 The Board continues to make its decisions in accordance with the *Act*, and the principles noted above.

12 At the commencement of the public hearing on September 19, 2011, NSPI notified the Board it had reached a Settlement Agreement (the "GRA Agreement") on most of the outstanding issues in the NSPI Application. The GRA Agreement was supported by most of the Formal Intervenors. The Board adjourned the hearing to provide an opportunity to all parties to file an executed copy of the GRA Agreement with the Board. The hearing reconvened on September 21, 2011, at which point NSPI witnesses explained the terms of the GRA Agreement and testified with respect to the outstanding issues.

3.0 Settlement Agreement

3.1 The Board's approach to settlement agreements

13 in its Decision dated November 5, 2008, the Board outlined its general approach to settlement agreements submitted to it for approval:

[12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.

[13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.

[14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.

2012	$56.24	$4.00	$60.24
2013	$61.77	$4.00	$65.77
2014	$63.86	$4.00	$67.86

This provides some measure of rate stability for NPB. Further, LRR customers will pay DSM and FAM riders in 2012.

211 The Board understands that, based on the evidence submitted by NPB, this design may not satisfy their business requirements. However, there is only so far the electricity system collectively can go, while still having a LRR that meets the legal test of recovering avoided costs and making a contribution to fixed costs. None of the Intervenors or their experts supported the LRR design submitted by NPB.

212 All customers are best served when all of the rates are based on cost of service and all customers' rates are calculated in the same manner. Cost of service studies which distribute all of the Utility's embedded costs, including the allowed rate of return, among all customer classes, are valuable tools which guide the Board in determining how a utility's revenue requirement should be recovered. However, as noted, the Board has the discretion under the *Act* to vary from cost based rates if, in the Board's opinion, it is in the public interest to do so and provided that other customers are not subjected to undue discrimination as a result.

213 The Board is reluctantly prepared to depart from traditional ratemaking (albeit not to the extent requested by NPB) and provide an opportunity for those customers to stay on the system and make, based on the Board's best judgment, a contribution to the fixed costs of the system. The Board is satisfied, on a balance of probabilities, that other customers will be better off under this amended LRR design with NPB on the system than if they leave. This is because the term is shorter — three years; the rate is based on annual variable incremental costs; there is a reasonable adder; and there is a re-opener if actual costs vary significantly from the rate assumptions.

214 NPB may ask, if the Board is inserting a re-opener into the rate, why not allow a five year term. The reason is that the Board sees no reasonable prospect that the rate would last for five years without having to be readjusted.

215 Board staff have calculated the estimated benefits to other customers and the savings to NPB if the full NPB load stays on the system at the LRR, as approved by the Board:

	2012	**2013**	**2014**
Benefits to other customers	$20 Million	$18 Million	$18 Million
Savings to NPB (before 150% capping of the ELI 2P-RTP)	$18.5 Million	$28.5 Million	$24.5 Million
Savings to NPB (after 150% capping of the ELI 2P-RTP)	$14 Million	$24 Million	$20 Million

6.2.4 Deferral

216 The GRA Agreement as filed, in paragraph 2, contains a deferral with respect to loss of revenue from the NPB load due to the uncertainty of the operations of NewPage and Bowater. The deferral clause is outlined in its entirety in the GRA Agreement. Given the continuing uncertainties surrounding these customers and the fact that the Board has amended the LRR from that originally applied for, the Board believes it appropriate to defer the impact of the LRR on other customers, using the GRA Agreement deferral mechanism, until 2013. Deferral would be consistent with the deferral of lost fixed non-fuel cost contributions from NPB as set out in paragraph 2 of the GRA Agreement. It would enable the Board to set rates for all customers without speculating how much contribution to the fixed costs NPB will make in 2012 if the revised LRR is put in place.

217 Therefore, the Board directs that the lost contribution to non-fuel costs (net of non-fuel variable O&M costs) as a result of implementing the LRR will be deferred for later recovery in the same manner as described in paragraph 2 of the GRA Agreement. In the Compliance Filing NSPI can simply file an addendum to the GRA Agreement (recognizing this is something imposed by the Board and not agreed to by the parties) that accomplishes this objective.

6.2.4.1 Terms and Conditions of the LRT

218 The tariff as submitted by NPB contemplated discussion and negotiation between NSPI and the Applicant for the LRR following which NSPI would apply to the Board for approval. NPB did not follow the process contemplated in the LRR they proposed. It is now clear to the Board that NPB made certain demands for terms of a LRR that NSPI could not support and, for that reason, NSPI did not bring the LRR forward. Strangely, NSPI assumed it could go through the hearing maintaining a neutral stance without commenting on the merits of the LRR as proposed. For reasons made clear by the Board at the hearing, that position by NSPI was not acceptable. In the view of the Board, NSPI had an obligation to provide the best advice it could to the Board and other parties on the proposed LRR design. After being directed to do so, NSPI did respond to Intervenor and Board questions and the evidence of NSPI was a critical factor in the Board's Decision.

219 NPB proposed, and NSPI appeared to agree, that there would not be a security deposit but that customers on the LRR would pay their power bill weekly. St would appear, however, that the normal disconnect procedures would continue to apply which could take some weeks. As pointed out by Mr. Drazen and Mr. Chernick, weekly payments under this LRR, assuming a full load, would be in excess of $2.0 Million and arrears could escalate quickly in the event of a

266 The Board approves the GRA Agreement, which represents a comprehensive resolution of most contested issues between NSPI and the Intervenors. It addresses a number of important elements raised in the NSPI Application.

267 It reduces NSPI's revenue requirement by $27.9 Million from the original requested increase of $94.4 Million. The resulting increase to the revenue requirement is $66.5 Million ($31.3 Million for fuel and $35.2 Million for non-fuel).

268 In its Application, NSPI requested that its current return on equity of 9.35% be increased to 9.6% (within a range of 9.35 to 9.85%). Under the terms of the GRA Agreement, the return on equity is reduced to 9.2% (within a range of 9.1% to 9.5%). This reduces the revenue requirement by $7.5 Million. Other costs are reduced as noted in this Decision.

Cost of Service

269 The Board agrees with the majority of the Intervenors that there is merit to review the current cost of service. The evidence presented notes that some of the assumptions and principles used in the COSS such as the current generation mix (including renewables) and emission control requirements need a review.

270 The Board's current 2012 Regulatory Schedule does not allow enough time for a review of the COSS. Therefore, the Board orders that NSPI plan for a COSS hearing in 2013.

Revenue to Cost Ratios

271 A change to the R/C ratio band of 95% — 105% is denied.

272 The Board recognizes the issue of the Small General and General Demand classes being on the high end of the R/C ratio band. The SBA has recommended that the R/C ratio for the Small General and General Demand classes be lowered to 1.03 from 1.05.

273 The Board agrees with the SBA's recommendation to lower the R/C ratio for these two customer classes to 1.03 for this Decision and NSPI is ordered to include this change in the Compliance Filing.

ELI 2P-RTP Rate

274 At the time the ELI 2P-RTP rate (which currently serves Bowater and NewPage) was approved, the Board noted it was innovative and new to NSPI and that there may be a need for the Board to review the terms and conditions once experience was gained under the rate.

275 The Board ordered an annual review. The reason for the annual review was so that the Board could carefully monitor experience under the rate to ensure that neither NSPI nor other customers were being disadvantaged. The Board also observes that the rate was ordered prior to the institution of the FAM which has added some complications.

276 The Board approves the changes to the rate as recommended by NSPI.

277 The Board is persuaded that these changes are necessary and prudent at this stage of the life of the rate. The reporting currently in place should continue.

278 To avoid rate shock to the ELI 2P-RTP rate customers, the Board finds that the increase should be limited to 150% of the average of the other classes. The Board finds scenario #2 suggested by Mr. Whalen, Board Counsel's consultant, is the appropriate mechanism to do this and directs NSPI to take this into account in the Compliance Filing.

279 The rate increases by customer class ordered in this Decision are estimated to be as follows:

	Rate Increase %
Residential	6.1
Sm Gen	2.5
Gen	2.8
Lg Gen	5.7
Sm Ind	5.6
Med Ind	7.5
Lg Ind	7.5
ELI 2P-RTP	8.5
Muni	7.4
Unmetered	-3.4

280 The average rate increase is approximately 5.6%.

Load Retention Rate

281 The Board concludes that it has jurisdiction under the *Public Utilities Act* to consider the application for a LRT based on the economic distress of extra large industrial customers.

282 Load retention tariffs are utilized in circumstances where providing the discounted tariff benefits not only the customers qualifying for the tariff but also the other customers on the system.

283 The test that the Board has applied in this case is whether, on a balance of probabilities, the other customers of NSPI would be better off by having NPB remain on the system (on the load retention rate) than those customers would be if NPB stopped taking service. The test is satisfied if the load retention rate fully recovers avoided costs of supplying NPB and makes a positive contribution to the fixed and common costs of NSPI. The Board will not, and indeed cannot, approve a rate in circumstances where the other customers are worse off (because they are subsidizing NPB) than they would be if these customers left the system.

284 The Board is not satisfied, on a balance of probabilities, that the LRR as applied for by NPB will recover avoided costs and make a positive contribution to fixed and common costs over the five year term. It has reached this conclusion for the following reasons:

- The Board concludes that a five year term is simply not supported by the preponderance of evidence. The likelihood is that the actual costs will be higher than the five year levelized costs calculated in the NPB Application.

- The Board agrees with the Intervenors that the $2.00 adder, combined with the five year term, does not provide a reasonable likelihood that the LRR will recover avoided costs and make a contribution to fixed costs.

- The Board is very concerned about the five year LRR structure as proposed, which provides NPB a significant advantage in the early years and escalates rapidly in years 3, 4 and 5 to rates in excess of what the mills now say they can afford to pay.

285 The Board, in the circumstances, could simply dismiss the NPB Application. However, that would not contribute to meeting the financial challenge that the two mills face, nor would it provide other customers at least some opportunity to receive a contribution to NSPI's system costs from the continued operation of the two mills.

286 In an attempt to find a solution that both meets the legal test and goes part way to meeting NPB's requirements, the Board is prepared to approve an amended LRR which has as its foundation recovery of NSPI's year-by-year estimate of avoided costs, as identified in Appendix C of Dr. Rosenberg's Pre-Filed Evidence, plus an adder. The term would be three years and the variable incremental cost would be the annual avoided cost in Appendix C in 2013 and 2014. In 2012, the Board would substitute $56.24, as taken from Undertaking U-9 filed by Mr. Whalen, which is based on rate case estimates.

287 The Board concludes that a LRR which uses the incremental costs as described above, is limited to a three year term, and has a $4.00 adder, would be appropriate. The Board reserves the right to adjust the LRR if actual costs vary significantly from LRR assumptions.

Accordingly, the rate would be as follows:

Year		***Variable Incremental Rate ($/MWh)***	***+ Adder***
2012	$56.24	$4.00	$60.24
2013	$61.77	$4.00	$65.77
2014	$63.86	$4.00	$67.86

This provides some measure of rate stability for NPB. Further, LRR customers will pay DSM and FAM riders in 2012.

288 The Board is satisfied, on a balance of probabilities, that other customers will be better off under this amended LRR design with NPB on the system than if they leave. This is because the term is shorter — three years; the rate is based on annual variable incremental costs; there is a reasonable adder; and there is a re-opener if actual costs vary significantly from the rate assumptions.

Deferral and Undertaking to Manage Costs

289 The GRA Agreement and this Decision defer the impact of any loss of load from NewPage or Bowater to 2013. Mr. Bennett has confirmed NSPI's undertaking to take all prudent and reasonable steps to minimize costs to other ratepayers if the NPB load, or a portion of it, remains off the system.

290 The Board has determined that a review of the deferral amount will occur in 2012 as part of a 2013 general rate application. In the event there is no general rate application in 2012 for 2013, the review will occur during the FAM proceeding in late 2012 and the deferral will be added to the issues list.

291 Whether the review of the deferral amount occurs in the context of the general rate application or the FAM proceeding, the Board and Intervenors will be able to question NSPI on whether it has taken all prudent and reasonable steps to minimize costs to other ratepayers if the NPB load, or a portion of it, remains off the system. If the actions taken by NSPI are deemed insufficient or imprudent by the Board, it will order accordingly.

292 An Order will issue following the Compliance Filing.

Appendix A

NOVA SCOTIA POWER INC.

2012 RATE APPLICATION P-892

- and -

2008 CarswellOnt 2830
Ontario Superior Court of Justice (Divisional Court)

Advocacy Centre for Tenants-Ontario v. Ontario (Energy Board)

2008 CarswellOnt 2830, [2008] O.J. No. 1970, 166 A.C.W.S. (3d) 384, 238 O.A.C. 343, 293 D.L.R. (4th) 684

Advocacy Centre for Tenants-Ontario and Income Security Advocacy Centre on behalf of Low-Income Energy Network (Appellant) and Ontario Energy Board (Respondent)

Cumming J., Kiteley J., and Swinton J.

Heard: February 25, 2008
Judgment: May 16, 2008
Docket: Toronto 273/07

Counsel: Paul Manning, Mary Truemner for Appellant
Michael Miller for Ontario Energy Board
Fred Cass, David Stevens for Enbridge Gas Distribution Inc.
Robert Warren for Consumers Council of Canada

Subject: Public; Constitutional

Headnote

Public law --- Public utilities — Regulatory boards — Practice and procedure — Judicial review — Jurisdiction of board

Utility company E Inc. applied before provincial energy board for approval of yearly distribution rates — Consumer advocacy network intervened at hearing in opposition of approval — Network sought introduction of rate affordability assistance program to make gas distribution rates affordable to low income consumers — Board refused to act on network's proposal — Board determined that it lacked jurisdiction to order implementation of low income affordability program — Network appealed from board's decision — Appeal allowed — Board had jurisdiction to establish rate affordability assistance plan for low income consumers purchasing distribution of natural gas from E Inc. — Board had to determine just and reasonable rates within context of objectives in s. 2 of Ontario Energy Board Act, 1998, which includes protecting interests of consumers with respect to prices — It was established that Board had jurisdiction to take into account ability to pay in setting rates, considering expansive wording of s. 36(2) and (3) of Act and purpose of legislation within context of Board's statutory objectives in s. 2, and being mindful of history of rate setting to date in giving efficacy to promotion of that legislative purpose.

The Ontario Energy Board (Board) was the provincial economic regulator for natural gas and electricity sectors in the province. A utility, E Inc., applied for approval of its annual gas distribution rates. A low-income energy advocacy group (LIEN) intervened in the application, alleging that the interests of low-income consumers were not protected without a rate affordability assistance program.

A majority of the Board held that LIEN's proposal amounted to an income redistribution scheme and determined that the Ontario Energy Board Act, 1998 did not explicitly grant the Board jurisdiction to order the implementation of a low income affordability program. The Board also held that it did not gain jurisdiction through the doctrine of necessary implication. LIEN appealed, seeking a declaration that the Board had jurisdiction to order a rate affordability assistance program for low income consumers of E Inc. within its franchise areas.

Held: The appeal was allowed.

(Per curiam): The Board had jurisdiction to establish a rate affordability assistance plan for low income consumers purchasing the distribution of natural gas from E Inc. The Board was authorized to employ any method or technique that it considered appropriate to fix just and reasonable rates. Although "cost of service" was necessarily a fundamental factor and starting point for determining rates, the Board had to determine just and reasonable rates within the context of the objectives in s. 2 of the Act, which includes protecting the interests of consumers with respect to prices.

The Board had jurisdiction to take into account ability to pay in setting rates, taking into account the expansive wording of s. 36(2) and (3) of the Act, considering the purpose of the legislation within the context of the Board's statutory objectives seen in s. 2, and being mindful of the history of rate setting to date in giving efficacy to the promotion of that legislative purpose.

(Per Swinton J., dissenting): The appeal should be dismissed. The Board was correct in concluding that it lacked jurisdiction to make the order sought. It was inevitable that the Board, in setting lower rates for the economically disadvantaged, would have to impose higher rates on other consumers. The Board's objectives are narrowly confined, and the Board's mandate did not include consideration of the economic and social requirements of consumers.

Were the Board to assume jurisdiction over a rate affordability assistance program, it would be taking on a significant new role as a regulator of social policy. Given that it would be a dramatic change in the role the Board historically played, as well as a departure from common law principles, it would require express language from the legislature to confer such jurisdiction. A determination of the need for a subsidy for low income consumers was better made by the legislature, which had the ability to consider the full range of existing programs and a wide range of funding options.

Board's jurisdiction in approving or fixing "just and reasonable rates" and adopting "any method or technique that it considers appropriate" in so doing.

39 The Board's regulatory power is designed to act as a proxy in the public interest for competition in view of a natural gas utility's geographical natural monopoly. Absent the intervention of the Board as a regulator in rate-setting, gas utilities (for the benefit of their shareholders) would be in a position to extract monopolistic rents from consumers, in particular, given a relatively inelastic demand curve for their commodity. Clearly, a prime purpose of the *Act* and the Board is to balance the interests of consumers of natural gas with those of the natural gas suppliers. The Board's mandate through economic regulation is directed primarily at avoiding the potential problem of excessive prices resulting because of a monopoly distributor of an essential service.

40 In performing this regulatory function, it is consistent for the Board to seek to protect the interests of *all* consumers vis-a-vis the reality of a monopoly. The Board must balance the respective interests of the utility and the collective interest of all consumers in rate setting. *Union Gas Ltd. v. Ontario (Energy Board)* (1983), 1 D.L.R. (4th) 698, 43 O.R. (2d) 489 (Ont. Div. Ct.) at 501 . The Board's regulatory power is primarily a proxy for competition rather than an instrument of social policy. *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.* (2006), 268 D.L.R. (4th) 408 (N.S. C.A.) at para. 33 [*Dalhousie*].

41 *Dalhousie* dealt with a request for a low income affordability program like that advanced by LIEN. However, it involved a consideration of rate setting under s. 67 (1) of the Nova Scotia *Public Utilities Act*, R.S.N.S. 1989, c. 380, which is very different in wording with respect to jurisdiction to that seen in s. 36 of the *Act* at hand. The Nova Scotia provision expressly provides that "rates shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate ...." Hence, the Nova Scotia Utility and Review Board found that it did not have jurisdiction to order low income affordability programs.

42 Section 36 of the *Act* has broad language, empowering the Board to set "just and reasonable" rates for the distribution of natural gas. The supply of natural gas can be considered a necessity that is available from a single source with prices set by the Board in the public interest. The Board has traditionally set rates on a "cost of service" basis, that is, on the basis of cost causality and employing a complex cost allocation exercise. In brief, this approach first looks to the utility's capital investments and maintenance costs including a fair rate of return to determine revenues required. The revenue requirement is then divided amongst the utility's rate paying consumers on a rate class basis (i.e., residential, commercial, industrial, etc.).

43 The rates have been traditionally designed with the principled objective of having each rate class pay for the actual costs that class imposes upon the utility. That is, the Board has sought to avoid inter-class and intra class subsidies. See RP-2003-0063 (2005) at 5. Consistent with this approach, the Board has refused the establishment of a special rate class to provide redress for aboriginal consumers. *Decision with Reasons* EBRO493 (1997) (O.E.B.). In that case, the Ontario Native Alliance ("ONA") requested the Board to order a utility to evaluate the establishment of a rate class for the purpose of providing a special rate class for aboriginal peoples. At 316-17, the Board stated:

> The Board is required by the legislation to "fix just and reasonable rates", and in doing so it attempts to ensure that no undue discrimination occurs between rate classes, and that the principles of cost causality are followed in allocating the underlying rates. While the board recognizes ONA's concerns, the Board finds that the establishment of a special rate class to provide redress for aboriginal consumers of Centra does not meet the above criteria and it is not prepared to order the studies requested by ONA.

44 This decision would be within the Board's jurisdiction and a like response to LIEN in the case at hand would arguably be consistent and reasonable. However, the Board in dealing with the ONA request did not decline on the basis of jurisdiction. Rather, it said that it should not exercise its jurisdiction as requested by ONA for the reasons given.

45 A low income rate affordability program would necessarily lead to treating consumer groups on a differentiated basis with higher prices for a majority of residential consumers and subsidization of the low-income subset by the majority group and/or other classes of consumers.

46 If the Board were to reduce the rates for one class of consumers based upon an income determinant, the Board would have to increase the rates for another class or classes of consumers. In effect, such a rate reduction would impose a regressive indirect tax upon those required to pick up the shortfall. Such an approach would arguably be a dramatic departure from the Board's regulatory function as implemented to date, which has been to protect the collective interest of consumers dealing with a monopoly supplier through a "cost of service" calculation and then to treat consumers equally through determining rates to pay for the "cost of service" on a cost causality basis for classes of consumers.

47 The Board's mandate has not been directed to the public interest in social or distributive justice through a differentiation of rates on the basis of income. That need is seen to be met through other mechanisms and programs legislated by the provincial Legislature and/or Parliament, for example, by refundable tax credits and social assistance.

48 Indeed, the provincial income tax legislation previously provided for public tax expenditures to assist low income consumers with rising electricity costs. This was done through an "Ontario home electricity payment" by reference to income levels. *Income Tax Act*, R.S.O. 1990, c.1.2, s. 8.6.1, as rep. by *Income Tax Amendment Act (Ontario Home Electricity Relief), 2006*, S.O. 2006, c. 18, s. 1. As well, Parliament has provided a one-time relief for energy costs to low income families and seniors in Canada through the *Energy Costs Assistance Measures Act*, S.C. 2005, c. 49.

49 The Board is an economic regulator, rather than a formulator of social policy. While no doubt the Board must take into account broad policy considerations, rate-setting is at the core of the Board's jurisdiction. *Garland v. Consumers' Gas Co.* (2000), 185 D.L.R. (4th) 536 (Ont. S.C.J.) at paras. 17, 45-46. Special rates for low income consumers would not be based upon economic principles of regulation but rather on the social principle of ability to pay. Any program to subsidize low income consumers would require a source of funding which is a matter of public policy. See generally *Rate Concessions to Poor Persons & Senior Citizens, Re*, 14 P.U.R. 4th 87 (U.S. Or. P.U.C. 1976).

50 This view of the nature and limit of the regulatory function is generally accepted as the norm in other jurisdictions. See for example *Washington Gas Light Co. v. Public Service Commission of the District of Columbia*, 450 A.2d 1187 (U.S. D.C. Ct. App. 1982) at para. 38; *State ex rel. Guste v. Council of New Orleans (City)*, 309 So. 2d 290 (U.S. La. S.C. 1975) at 294 .

51 The historical common law approach for public utility regulation has been that consumers with similar cost profiles are to be treated equally so far as reasonably possible with respect to the rates paid for services. See, for example, *St. Lawrence Rendering Co. v. Cornwall (City)*, [1951] O.R. 669 (Ont. H.C.) at 683; *Chastain v. British Columbia Hydro & Power Authority* (1972), 32 D.L.R. (3d) 443 (B.C. S.C.) at 454 ; *Canada (Attorney General) v. Toronto (City)* (1893), 23 S.C.R. 514 (S.C.C.) at 519 -520.

Conclusions on the Board's Jurisdiction

52 We agree that the traditional approach of "cost of service" is the root principle underlying the determination of rates by the Board because that is necessary to meet the fundamental, core objective of balancing the interests of all consumers and the natural monopoly utility in rate/price setting.

53 However, the Board is authorized to employ "any method or technique that it considers appropriate" to fix "just and reasonable rates." Although "cost of service" is necessarily an underlying fundamental factor and starting point to determining rates, the Board must determine what are "just and reasonable rates" within the context of the objectives set forth

in s. 2 of the *Act*. Objective #2 therein speaks to protecting "the interests of consumers with respect to prices."

54 The "cost of service" determination will establish a benchmark global amount of revenues resulting from an estimated quantity of units of natural gas or electricity distributed. The Board could use this determination to fix rates on a cost causality basis. This has been the traditional approach.

55 However, in our view, the Board need not stop there. Rather, the Board in the consideration of its statutory objectives might consider it appropriate to use a specific "method or technique" in the implementation of its basic "cost of service" calculation to arrive at a final fixing of rates that are considered "just and reasonable rates." This could mean, for example, to further the objective of "energy conservation", the use of incentive rates or differential pricing dependent upon the quantity of energy consumed. As well, to further the objective of protecting "the interests of consumers" this could mean taking into account income levels in pricing to achieve the delivery of affordable energy to low income consumers on the basis that this meets the objective of protecting "the interests of consumers with respect to prices." discretion

56 The Board is engaged in rate-setting within the context of the interpretation of its statute in a fair, large and liberal manner. It is not engaged in setting social policy.

57 This is not, of course, to imply any preferred course of action in rate setting by the Board. The Board in its discretion may determine that "just and reasonable rates" are those that follow from the approach of "cost causality" once the "cost of service" amount is determined. That is, the principle of equality of rates for consumers within a given class (e.g., residential consumers) may be viewed as the most just and reasonable approach. A determination by the Board that all residential gas consumers (with relatively minor deviations through such programs as the "Winter Warmth Program") pay the same distribution rates is not in itself discriminatory on a prohibited ground. Indeed, it can be seen as a non-discriminatory policy in terms of prices paid. N.B.

58 Nor is it to suggest that as a matter of public policy, objectives of distributive justice or conservation in respect of energy consumption are best achieved by rate setting as compared to, for instance, tax expenditures or social assistance devised and implemented by the Legislature through mechanisms independent of the operation of the *Act*. It is noted that the Minister is given the authority in s. 27 of the *Act* to issue policy statements as to matters that the Board must pursue; however, the Minister has not issued any policy statement directing the board to base rates on considerations of the ability to pay. Moreover, the power granted to a regulatory authority "must be exercised reasonably and according to the law, and cannot be exercised for a collateral object or an extraneous and irrelevant purpose, however

commendable." *Multi-Malls Inc. v. Ontario (Minister of Transportation & Communications)* (1976), 14 O.R. (2d) 49 (Ont. C.A.) at 55 . As we have said, cost of service is the starting point building block in rate setting, to meet the fundamental concern of balancing the interests of all consumers with the interests of the natural monopoly utility.

59 Nor does our conclusion presume as to what methods or techniques may be available in determining "just and reasonable rates." Efficiency and equity considerations must be made. Rather, this is to say only that so long as the global amount of return to the utility based upon a "cost of service" analysis is achievable, then the rates/prices (and the methods and techniques to determine those rates/prices) to generate that global amount is a matter for the Board's discretion in its ultimate goal and responsibility of approving and fixing "just and reasonable rates."

60 The issue before the Court is that of jurisdiction, not how and the manner by which the Board should exercise the jurisdiction conferred upon it.

61 In our view, and we so find, the Board has the jurisdiction to take into account the ability to pay in setting rates. We so find having taken into account the expansive wording of s. 36 (2) and (3) of the statute and giving that wording its ordinary meaning, having considered the purpose of the legislation within the context of the statutory objectives for the Board seen in s. 2, and being mindful of the history of rate setting to date in giving efficacy to the promotion of the legislative purpose.

62 We also find that that interpretation is appropriate taking into account the criteria articulated in *Driedger*, above, namely it complies with the legislative text, it promotes the legislative purpose and the outcome is reasonable and just.

63 As indicated above, a statutory administrative tribunal obtains its jurisdiction from explicit powers or implicit powers. Having found that the jurisdiction to consider ability to pay in rate setting is explicitly within the *Act*, we need not consider the doctrine of necessary implication or the related principle of implied exclusion.

The issue of the Canadian Charter of Rights and Freedoms

64 Before concluding, it is appropriate to mention the submission made on behalf of LIEN in respect of s. 15 (1) of the *Canadian Charter of Rights and Freedoms*, Part 1 of the *Constitution Act, 1982*, being Schedule B to the *Canada Act, 1982* (U.K.), c. 11 (the "*Charter*").

65 LIEN says it raises the *Charter* simply within the context of it being an interpretive tool in discerning the meaning of an asserted ambiguous s. 36 of the *Act*. LIEN says it does not raise any issue that the *Act* or the Board's actions or inactions are contrary to the *Charter*.

66 LIEN argues that in the absence of clear statutory provisions, the requirement for "just and reasonable rates" must be interpreted to comply with s. 15. The *Charter* applies to provincial legislation and can be used as an interpretive tool. *R. v. Jackpine*, [2006] 1 S.C.R. 554, [2006] S.C.J. No. 15 (S.C.C.) at para. 18. In our view, as stated above, the *Act* provides the Board with the requisite jurisdiction without having to look to the *Charter*.

67 While we heard submissions from LIEN, we declined to hear from counsel for the respondents on this issue. We agree with our colleague Swinton J. that such an argument requires a full evidentiary record.

Disposition

68 For the reasons given, the appeal is allowed and it is declared that the Board has the jurisdiction to establish a rate affordability assistance program for low income consumers purchasing the distribution of natural gas from the utility, EGD.

69 All parties agree that there is not to be any award of costs in respect of this appeal.

Swinton J.:

70 The sole issue in this appeal is whether the Ontario Energy Board (the "Board") erred in holding that it had no jurisdiction, when setting residential rates for gas distribution, to order a rate affordability program for low income consumers. In my view, the majority of the Board was correct in concluding that the Board lacked jurisdiction to make such an order.

71 The majority of the Board predicated its decision on the understanding that the appellants' proposal contemplated the establishment of a rate group for low income residential consumers that would be funded by general rates. I, too, proceed on that assumption. While there were no details of a specific program put forth by the appellants during the hearing, it is inevitable that the Board, in setting lower rates for the economically disadvantaged, would have to impose higher rates on other consumers.

The Board's Practice in Setting Rates

72 Pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the "Act"), the Board has authority to set rates for both gas and electricity. It has traditionally set rates for gas through a "cost of service" assessment, in which it seeks to determine a utility's total cost of providing service to its customers over a one year period (the "test year"). According to the Board's factum, these costs include the rate base (which is essentially the net book value of the utility's total capital investments) and the utility's operational and maintenance costs for the test year, among other things. The utility's total costs for the test year (usually including a rate of return on the rate base portion) forms the revenue requirement. The

revenue requirement is then divided amongst the utility's ratepayers on a rate class basis (that is, residential, small commercial, industrial, etc.).

73 With respect to gas, it has always been the Board's practice to allocate the revenue requirement to the different rate classes on the basis of how much of that cost the rate class actually causes ("cost causality"). To the greatest extent possible, the Board has striven to avoid inter-class subsidies (see, for example, Decision with Reasons, RP-2003-0063 (2005), p. 5).

The Proper Approach to Statutory Interpretation

74 To determine the issue in this appeal, it is necessary to consider the powers conferred on the Board by its constituent legislation, the *Ontario Energy Board Act*. That Act must be interpreted using the modern principles of statutory interpretation described by Professor Ruth Sullivan in *Driedger on the Construction of Statutes* (3rd ed.) (Toronto: Butterworths, 1994) as follows:

> There is only one rule in modern interpretation, namely, courts are obliged to determine the meaning of legislation in its total context, having regard to the purpose of the legislation, the consequences of proposed interpretations, the presumptions of special rules of interpretation, as well as admissible external aids. In other words, the courts must consider and take into account all relevant and admissible indicators of legislative meaning. After taking these into account, the court must then adopt an interpretation that is appropriate. An appropriate interpretation is one that can be justified in terms of
>
> > (a) its plausibility, that is, its compliance with the legislative text; (b) its efficacy, that is, its promotion of the legislative purpose; and (c) its acceptability, that is, the outcome is reasonable and just. (at p. 131)

75 The words of a statute are to be read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme of the Act, its objects, and the intent of the Legislature (*ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, [2006] 1 S.C.R. 140 (S.C.C.) at para. 37).

The Words of the Provision in Issue

76 Subsection 36(2) of the Act gives the Board the broad authority to approve or fix "just and reasonable" rates for the distribution of gas. On its face, those words might encompass the power to set rates according to income. However, the words do not explicitly confer the power to do so, and the Supreme Court of Canada commented in *ATCO*, *supra* that a discretionary grant of authority to a tribunal cannot be viewed as conferring unlimited discretion. A regulatory tribunal must interpret its powers "within the confines of

the statutory regime and principles generally applicable to regulatory matters, for which the legislature is assumed to have had regard in passing that legislation" (at para. 50).

77 The appellants also rely on s. 36(3), which states that in approving or fixing just and reasonable rates, the Board may adopt "any method or technique that it considers appropriate". These words were added to the Act in 1998. Examples of methods or techniques used by the Board for setting gas distribution rates are cost of service regulation and incentive regulation.

78 On its face, the words of s. 36(3) do not confer the jurisdiction to provide special rates for low income customers. The subsection replaced an earlier provision of the Act which required a traditional cost of service analysis in setting rates. I agree with the conclusion of the Board majority as to the meaning of s. 36(3) (Reasons, p. 10):

> It gives the Board the flexibility to employ other methods of ratemaking in fixing just and reasonable rates, such as incentive ratemaking, rather than the traditional costs of service regulation specified in section 19 of the old Act. The change in the legislation was coincident with the addition of the regulation of the electricity sector to the Board's mandate. The granting of the authority to use methods other than cost of service to set rates for the gas sector was an alignment with the non-prescriptive authority to set rates for the electricity sector. The Board is of the view that if the intent of the legislature by the new language was to include ratemaking considering income level as a rate class determinant, the new Act would have made this provision explicit given the opportunity at the time of the update of the Act and the resultant departure from the Board's past practice.

The Regulatory Context

79 According to longstanding principles governing public utilities developed under the common law, a public utility like the respondent Enbridge Gas Distribution Inc. ("Enbridge") must treat all its customers equally with respect to the rates they pay for a particular service (*Canada (Attorney General) v. Toronto (City)* (1893), 23 S.C.R. 514 (S.C.C.) at 519 -20; *St. Lawrence Rendering Co. v. Cornwall (City)*, [1951] O.R. 669 (Ont. H.C.) at 683; *Chastain v. British Columbia Hydro & Power Authority* (1972), 32 D.L.R. (3d) 443 (B.C. S.C.) at 454).

80 As noted in the Board's majority reasons, the Board is, at its core, an economic regulator (Reasons, p. 4). Rate setting is at the core of its jurisdiction (*Garland v. Consumers' Gas Co.* (2000), 185 D.L.R. (4th) 536 (Ont. S.C.J.) at para. 45). I agree with the majority's description of economic regulation as being "rooted in the achievement of economic efficiencies, the establishment of fair returns for natural monopolies and the development of appropriate cost allocation methodologies" (Reasons, p. 4).

81 Historically, in setting rates, the Board has engaged in a balancing of the interests of the regulated utility and consumers. The Board has not historically balanced the interests of different groups of consumers. As the Divisional Court stated in *Union Gas Ltd. v. Ontario (Energy Board)* (1983), 43 O.R. (2d) 489 (Ont. Div. Ct.) at p. 11:

> ... it is the function of the O.E.B. to balance the interest of the appellant in earning the highest possible return on the operation of its enterprise (a monopoly) with the conflicting interest of its customers to be served as cheaply as possible.

See, as well, *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.) at 192.

82 In a similar vein, the Supreme Court in *ATCO*, *supra* spoke of a "regulatory compact" which ensures that all customers have access to a utility at a fair price. The Court went on to state (at para. 63):

> Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specified area at rates that will provide companies the opportunity to earn a fair rate of return for all their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers of their defined territories, and are required to have their rates and certain operations regulated...

The Court described the object of the Act "to protect both the customer *and* the investor" (at para. 64).

83 The Legislature, in conferring power on the Board, must be taken to have had regard to the principles generally applicable to rate regulation (*ATCO*, *supra* at paras. 50 and 64). I agree with the submission of Enbridge that those principles are the following:

> (a) customers of a public utility must be treated equally insofar as the rate for a particular service or class of services is concerned; and
>
> (b) the Legislature will be presumed not to have intended to authorize discrimination among customers of a public utility unless it has used specific words to express this intention.

84 Thus, the considerations of justice and reasonableness in the setting of rates have been and are those between the utility and consumers as a group, not among different groups of consumers based on their ability to pay.

Other Provisions of the Act

85 In applying s. 36(2), the Board must be bound by the objectives set out in s. 2 of the Act, which includes

> 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

86 The appellants submit that these words are broad enough to permit the Board to order a rate affordability assistance program. However, that is not obvious from the words used, which refer to "consumers" as a whole, and not to any particular subset of consumers. Indeed, it can be argued that any low income rate affordability program would run counter to the stated objective, given that such a program must almost certainly be funded through higher rates paid by other consumers. The result would be to provide benefits to one group of consumers at the expense of others.

87 The reason for this conclusion lies in the Board's historical approach to rate setting, as described earlier in these reasons. The Board sets a revenue requirement for utilities before allocating those costs to the different rate classes. The only way the utility could recover its revenue requirement, given a rate class with lower rates for low income consumers, would be to increase the rates charged to other classes. Therefore, such higher prices can not be seen as protecting the interests of consumers with respect to prices, as set out in objective 2.

88 Moreover, the Act contains an explicit provision in s. 79 that allows the Board to provide rate protection for rural and remote customers of electricity distributors. Subsection 79(1) provides:

> The Board, in approving just and reasonable rates for a distributor who delivers electricity to rural or remote consumers, shall provide rate protection for those consumers or prescribed classes of those consumers by reducing the rates that would otherwise apply in accordance with the prescribed rules.

Section 79 also provides grandfathering for those who had a subsidy prior to the change in the Act. As well, it explicitly allows the distributor to be compensated for the subsidized rates through contributions from other consumers, as provided by the regulations.

89 This section was added to the Act in 1998, when the Board was given the authority over electricity rate regulation. Section 79 ensured the ongoing protection of rural rates put in place when electricity distribution was regulated by Ontario Hydro.

90 One of the principles of statutory interpretation is "implied exclusion". As Professor Sullivan has stated, this principle operates "whenever there is reason to believe that if the legislature had meant to include a particular thing within its legislation, it would have referred

to that thing expressly" (*supra*, p. 186). While the purpose of s. 79 of the Act was to protect a pre-existing policy to assist rural and remote residential consumers, nevertheless, it is telling that there is no similar explicit power to order special rates or rate subsidies for other groups elsewhere in the Act.

The Significance of Ordering Rate Affordability Programs

91 An appropriate interpretation can be justified in terms of its promotion of the legislative purpose and the reasonableness of the outcome (see Sullivan, quoted above at para. 5).

92 The ability to order a rate affordability program would significantly change the role that the Board has played — indeed, the majority of the Board stated a number of times that the proposal to base rates on income level would be a "fundamental" departure from its current practice. In the past, the Board has acted as an economic regulator, balancing the interests of the utility and its shareholders against the interests of consumers as a group. Were it to assume jurisdiction over rate affordability programs, it would carry out an entirely different function. It would enter into the realm of social policy, weighing the interests of low income consumers against those of other consumers. This is not a role that the Board has traditionally played. This is not where its expertise lies, nor is it well-suited to taking on such a role.

93 An examination of the particular case before the Board illustrates this. The appellants seek a rate affordability assistance program for gas in response to Enbridge's application for a rate increase for gas distribution — that is, for the *delivery* of natural gas. Customers can make arrangements for the purchase of the commodity of natural gas with a variety of suppliers in the competitive market. Therefore, were the Board to assume jurisdiction to order a rate affordability assistance program here, it could address only one part of the problem that low income consumers face in meeting their heating costs — the cost of distribution of gas.

94 In addition, the Board would have to consider eligibility criteria for a rate affordability assistance program that reasonably would take into account existing programs for assistance to low income consumers. Obviously, this would include social assistance programs. As well, Enbridge, in its factum, has identified other programs which provide assistance for low income consumers. For example, the Ontario government has implemented a program to assist low income customers with rising electricity costs through amendments to income tax legislation (*Income Tax Act*, R.S.O. 1990, c. I.2, s. 8.6.1, as amended S.O. 2006, c.18, c.1). At the federal level, there was one-time relief for low income families and senior citizens provided by the *Energy Costs Assistance Measures Act*, S.C. 2005, c. 49.

95 Moreover, in order to cover the lower costs, the Board would have to increase the rates of other customers in a manner that would inevitably be regressive in nature, as it is difficult

to conceive how the Board would be able to determine, in a systematic way, the ability of these other customers to pay.

96 Clearly, the determination of the need for a subsidy for low income consumers is better made by the Legislature. That body has the ability to consider the full range of existing programs, as well as a wide range of funding options, while the Board is necessarily limited to allocating the cost to other consumers. The relative advantages of a legislative body in establishing social programs of the kind proposed are well described in the following excerpt from a decision of the Oregon Public Utility Commissioner *Rate Concessions to Poor Persons & Senior Citizens, Re*, 14 P.U.R. 4th 87 (U.S. Or. P.U.C. 1976) at p. 94):

> Utility bills are not poor persons' only problems. They also cannot afford adequate shelter, transportation, clothing or food. The legislative assembly is the only agency which can provide comprehensive assistance, and can fund such assistance from the general tax funds. It has the information and responsibility to deal with such matters, and can do so from an overall perspective. It can determine the needs of various groups and compare those needs to existing social programs. If it determines a special program is needed to deal with energy costs, it can affect all energy sources rather than only those the commissioner regulates.
>
> With clear authority to establish social welfare policy, the legislative assembly also can monitor all state and federal welfare programs and the sources and extent of aid given to different groups. Without such overview, as independent agencies aid various segments of society, the total aid given each group is unknown, and unequal treatment of different groups becomes likely.

97 Where the issue of rate affordability programs has arisen in other jurisdictions, courts and boards have ruled that a public utilities board does not have jurisdiction to set rates based on ability to pay (see, for example, *Washington Gas Light Co. v. Public Service Commission of the District of Columbia*, 450 A.2d 1187 (U.S. D.C. Ct. App. 1982) at para. 38; *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.* (2006), 268 D.L.R. (4th) 408 (N.S. C.A.) at 419 ; Alberta Energy and Utilities Board Decision 2004-066 [*ENMAX Power Corp., Re*, 2004 CarswellAlta 2078 (Alta. E.U.B.)], Section 9.2.6 at 161, as well as the Oregon case, *supra*).

98 The appellants distinguish the *Dalhousie* case because the Nova Scotia legislation is different from Ontario's. Specifically, s. 67(1) of the *Public Utilities Act*, R.S.N.S. 1989, c. 380 provides that "[a]ll tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate".

99 While the language of the two statutes does differ, nevertheless, the reasons of the Nova Scotia Court of Appeal make it clear that the Board's role is not to set social policy. At para.

33, Fichaud J.A, observed, "The Board's regulatory power is a proxy for competition, not an instrument of social policy."

100 Moreover, the principle in s. 67(1) of the Nova Scotia Act requiring that rates be charged equally is a codification of the common law, set out earlier in these reasons. The Ontario Board has long operated according to the same principles.

101 The appellants submit that the recent decision in *Allstream Corp. v. Bell Canada*, [2005] F.C.J. No. 1237 (F.C.A.) assists their case. There, the Federal Court of Appeal upheld a decision of the Canadian Radio-Television and Telecommunications Commission (the "CRTC") approving special facilities tariffs submitted by Bell for the provision of optical fibre services pursuant to certain customer-specific arrangements. All but one related to a Quebec government initiative aimed at supporting the construction of broadband networks for rural municipalities, school boards and other institutions. The Court determined that the Commission's decision approving the tariffs was not patently unreasonable, given the exceptional circumstances of the case that justified a deviation from the normal practice of rate determination. The Court noted that the Commission considered matters that were not purely economic, but noted that such considerations were part of the Commission's wide mandate under s. 7 of the *Telecommunications Act*, S.C. 1993, c. 38 (at paras. 34-35).

102 Section 7 of that Act, unlike s. 2 of the *Ontario Energy Board Act*, expressly includes the power "to respond to the economic and social requirements of users of telecommunications services" (s. 7(h)), as well as to enrich and strengthen the social and economic fabric of Canada and its regions (s. 7(a)). Moreover, while s. 27(2)(b) of that Act forbids unjust discrimination in rates charged, s. 27(6) explicitly permits reduced rates, with the approval of the Commission, for any charitable organization or disadvantaged person.

103 In contrast to the broad mandate given to the CRTC, the objectives of the Board are much more confined. When the Board's objectives go beyond the economic realm, specific reference has been made to other objectives, such as conservation and consumer education (s. 2 (5) and (6)). There is no reference to the consideration of economic and social requirements of consumers.

104 The appellants have also pointed out that the Board has in the past authorized programs that transfer benefits to lower income customers. The Winter Warmth program is one in which individuals can apply for emergency financial relief with heating bills. It is triggered by an application from a particular customer, and the program is funded by all customers. The fact that the Board has approved this charitable program does not lead to the conclusion that it has jurisdiction to set rates on the basis of income level.

105 With respect to the Demand Side Management (DSM) programs, the majority of the Board explained that this is not equivalent to a rate class based on income level. At p. 11 of its Reasons, the majority stated,

> The Board is vigilant in ensuring that customer groups are afforded the opportunity to receive the benefits of the costs charged. In the case of Demand Side Management (DSM) programs, for example, the Board has ordered that specific funding be channeled for programs aimed at low income customers. It cannot be argued that this constitutes discriminatory pricing. Rather, the contrary. It is an attempt to avoid discrimination against low income customers who also pay for DSM programs but may not have equal opportunities to take advantage of these programs.

106 Were the Board to assume jurisdiction to order a rate affordability assistance program, it would be taking on a significant new role as a regulator of social policy. Given the dramatic change in the role that it has historically played, as well as the departure from common law principles, it would require express language from the Legislature to confer such jurisdiction

Jurisdiction by Necessary Implication

107 In order to impute jurisdiction to a regulatory body, there must be evidence that the exercise of the power in question is a practical necessity for the regulatory body to accomplish the goals prescribed by the Legislature (*ATCO*, *supra* at paras. 51, 77). In this case, there is no evidence that the power to implement a rate affordability assistance program is a practical necessity for the Board to meet its objectives as set out in s. 2.

The Role of the Charter

108 The appellants submit that the values found in s. 15 of the *Canadian Charter of Rights and Freedoms* should be considered in the interpretation of the ratemaking provisions of the Act. However, the Charter has no relevance in interpretation unless there is genuine ambiguity in the statutory provision (*R. v. Jackpine*, [2006] 1 S.C.R. 554 (S.C.C.) at paras. 18-19). A genuine ambiguity is one in which there are "two or more plausible readings, each equally in accordance with the intentions of the statute" (at para. 18).

109 In my view, there is no ambiguity in the interpretation of s. 36 of the Act, and therefore, there is no need to resort to the Charter.

110 In any event, the appellants' argument is, in fact, that the failure of the Board to order a rate affordability program is discriminatory on the basis of sex, race, age, disability and social assistance, because of the adverse impact on these groups (Factum, para. 43, as well as para. 47). Such an argument can not be made without a full evidentiary record, and

the inclusion of statistical material in the Appeal Book is not a sufficient basis on which to address this equality argument.

Conclusion

111 For these reasons, I am of the view that the majority decision of the Board was correct, and that the Board has no jurisdiction to order rate affordability assistance programs for low income consumers. Therefore, I would dismiss the appeal.

Appeal allowed.

End of Document

1985 CarswellMan 74
Manitoba Court of Appeal

Brandon Transit Consumers Assn. Inc. v. Brandon (City)

1985 CarswellMan 74, 18 D.L.R. (4th) 459, 30 M.P.L.R. 78, 32 A.C.W.S. (2d) 309, 34 Man. R. (2d) 36

BRANDON TRANSIT CONSUMERS ASSOCIATION INC. v. CITY OF BRANDON

Monnin C.J.M., Matas and O'Sullivan JJ.A.

Heard: January 29, 1985
Judgment: April 1, 1985
Docket: No. 305/84

Counsel: *L.A. Cherniack* and *A. Peltz*, for appellant.
R.W. Singleton and *B.M. Midwinter*, for respondent.
K.D. Munroe and *R.A. Dewar*, for Public Utilities Board.

Subject: Public; Torts; Contracts

Headnote

Carriers --- Fares and freight rates — Regulation of rates — Municipal transportation fares

Public Utility Board — Transit fares — Fare increases — Board erring in not taking into account quality and quantity of service — Board having jurisdiction to approve fare increase more than one year before coming into effect — Municipal Act, S.M. 1970, c. 100 (also C.C.S.M., c. M225) — Public Utilities Board Act, R.S.M. 1970, c. P280 (also C.C.S.M., c. P280) — Brandon Charter, S.M. 1939, c. 95.

The applicant, BTCA claimed to represent some of the citizens who made use of the municipal bus service. The applicant had applied to the Public Utility Board for an investigation, hearing and review with respect to the services provided by the bus service but the board had declined to hear the application. The municipality then applied to the board for approval of a by-law increasing transit fares in two stages. The applicant intervened. It raised no objection to the first fare increase but opposed the second, submitting that the quality of service did not warrant as large an increase as the municipality proposed. Both increases were approved. The board declined at the hearing to consider the present or anticipated quality and adequacy of service. The applicant appealed on the grounds that one increase was approved too long in advance of its effective date and that the board refused to consider quality and adequacy of service though bound to do so.

Held:

The appeal was allowed.

The provisions of the Municipal Act, s. 267(1), the City of Brandon Charter, s. 49J(7) and the Public Utilities Board Act, ss. 63(1), 64, 74(1) and 84(1) stipulate that, while the municipality need not in proposing fare rate increases have regard to any criterion other than cost, the board must, in considering approval, have regard to quality of service as well as rates in order to determine what in its opinion, is just and reasonable. The board made an error of law in deciding the issue solely under the provisions of s. 267 of the Municipal Act. The board did, however, have jurisdiction to approve a fare increase more than a year before it was due to come into effect.

Per Monnin C.J.M. (dissenting)

The board had jurisdiction to approve a fare increase more than one year before it is due to take effect. In addition, the board did not consider itself fettered by s. 267(1) of the Municipal Act. The board looked at the entire situation as it then existed. It did not exceed its jurisdiction or err in law by allowing the fare increase. In its approval, the board did take into account the quality and quantity of the service as it existed at the time.

Table of Authorities

Cases considered:

B.C. Elec. Ry. v. B.C. Pub. Utilities Comm., [1960] S.C.R. 837, 33 W.W.R. 97, 82 C.R.T.C. 32, 25 D.L.R. (2d) 689 (S.C.C.) — *referred to*

D.C. Transit System Inc. v. Washington Metro. Area Transit Comm., 422 F. 2d 394 (1972) (certiorari denied by United States Supreme Court, 93 S. Ct. 688) — *referred to*

Dartmouth, Re (1976), 17 N.S.R. (2d) 425 (N.S. C.A.) — *referred to*

P.U.C. v. N.S. Power Corp. (1976), 18 N.S.R. (2d) 692, 75 D.L.R. (3d) 72 (N.S. C.A.) — *referred to*

T.A.S. Communications Systems Ltd. v. Nfld. Tel. Co. (1983), 44 Nfld. & P.E.I.R. 114, 130 A.P.R. 114, 2 D.L.R. (4th) 647 (Nfld. C.A.) — *referred to*

Statutes considered:

Brandon Charter, S.M. 1939, c. 95 —

s. 49J(7) [en. 1970, c. 108, s. 1].

Municipal Act, S.M. 1970, c. 100 (also C.C.S.M., c. M225),

s. 267(1).

Public Utilities Board Act, R.S.M. 1970, c. P280 (also C.C.S.M., c. P280) ss. 63(1), 64, 74(1), 84(1).

APPEAL from a decision of the Public Utility Board of Manitoba.

O'Sullivan J.A. (Matas J.A. **concurring):**

1 There is an ongoing dispute between the applicant and the City of Brandon about the quality of the bus service provided by the city under powers given to it by the Munnicipal Act, S.M. 1970, c. 100 (also C.C.S.M., c. M225). The applicant, Brandon Transit Consumers Association Inc., herein called "BTCA", claims to represent some of the citizens who make use of the bus service.

2 The applicant applied to the Public Utility Board in May 1983 for an investigation, hearing and review with respect to the services but the Board had declined to hear the application at that time. Then the city applied to the board for approval of a by-law increasing transit fares in two stages: the one to come into effect September 1, 1984 and the other September 1, 1985. The applicant intervened. It raised no objection to the first fare increase but opposed the second, submitting that the quality of service did not warrant so large an increase as the city was asking.

3 The board held a hearing and gave approval of both increases but declined at the hearing to consider the quality and adequacy of the service being provided or anticipated to be provided on September 1, 1985. BTCA obtained leave to appeal the board's decision but only insofar as it purports to approve of the second fare increase. There are two grounds of appeal: one, that the increase authorized for 1985 was made too long in advance of the effective date; the other, that the board refused to consider quality and adquacy of service though bound to do so.

4 This Court is not itself a regulatory body. We have nothing to say about the quality or adequacy of Brandon's bus service. These are matters for the Public Utility Board, the city council, the voters of Brandon and the Legislature of Manitoba.

5 What we are required to do, however, is to correct any errors of law that might have been made by the board and to ensure that the board does not exceed its jurisdiction.

6 In the case before us, it is acknowledged on all sides that the board's approval of the 1985 fare increases was made without taking into account applicant's submission. It is not suggested that the board refused to consider the issue of service in separate proceedings, nor is it suggested that the board did not consider service when it approved the fares. As stated by counsel for the board in his factum:

> ... the order presupposes a given level of service and approves rates on the basis of that level. The Board did not consider certain elements of service such as time-tables and routes.

Counsel for the board submits:

> Such considerations were outside the scope of the application as set out in section 267(1)(b) of the Municipal Act.

7 This is essentially the position taken also by counsel for the City of Brandon.

8 It can be seen, therefore, that the board's failure to take into account matters such as routes and timetables was due not to an exercise of its discretion but because of its understanding of the law. The board accepted the advice of its lawyers and that of the city's lawyers that these considerations were outside the scope of the application. Counsel for the BCTA, on the other hand, submits that s. 267(1)(b) of the Municipal Act is subject to the Public Utilities Board Act, R.S.M. 1970, c. P280 (also C.C.S.M., c. P280), and that the board erred in applying its erroneous understanding of the law. In so doing, counsel suggests that the board exceeded its jurisdiction to approve of the second fare increase by reason of its having declined to exercise its jurisdiction to consider the quality and nature of the service in relation to the fare increases.

9 It is not necessary for us to decide the question whether the point of law goes to jurisdiction or not. What we must be concerned with is whether counsel for the board and for the city are right in their interpretation of the law as it applies to the Brandon transit system.

10 It is conceded by all the parties that in ordinary cases regulatory bodies in general, and the Public Utility Board in particular, may consider the nature, quality and adequacy of service

before authorizing or approving of increases in rates or tolls.

11 For example, s. 63(1) the Public Utilities Board Act says:

> 63(1) The board has jurisdiction in all questions relating to the transportation of goods or passengers by any corporation, municipal or otherwise, on any part of any tram-line, or street railway line, or steam railway or motor bus line under the jurisdiction of the Legislature, and may authorize or require any such corporation to carry goods or passengers on its lines or any part thereof for any period of time and at such prices as it may fix.

12 Section 64 gives the board power to hold an investigation into all matters relating to the nature and quality of the service on being requested to do so by a citizen or by the Minister or on its own initiative.

13 Section 74(1) reads:

> 74(1) The board has a general supervision over all public utilities and the owners thereof subject to the legislative authority of the Legislature and may make such orders regarding equipment, appliances, safety devices, extension of works or systems, reporting and other matters as are necessary for the safety or convenience of the public or for the proper carrying out of contract, charter or franchise involving the use of public property or rights.

14 Among other sections in point, it may be sufficient to note only one other section, s. 84(1) which says:

> 84(1) No change in any existing individual rates, joint rates, tolls, charges or schedules thereof or any commutation, mileage or other special rates shall be made by any owner of a public utility, nor shall any new schedule of any such rates, tolls or charges be established until the changed rates or new rates are approved by the board, when they shall come into force on a date to be fixed by the board; and the board may, either upon written complaint or upon its own initiative, hear and determine whether the proposed increases, changes, or alterations are just and reasonable.

15 It is the submission of counsel for BTCA that the board, having determined to hold a hearing, was required to consider all material that was placed before it relating to the issue of whether the changes in rates and tolls were just and reasonable.

16 For an interpretation of the meaning of "just and reasonable" in this context, counsel referred us to the decision of the Supreme Court of Canada in B.C. Elec. Ry. v. B.C. Pub. Utilities Comm., [1960] S.C.R. 837, 33 W.W.R. 97, 82 C.R.T.C. 32, 25 D.L.R. (2d) 689 (S.C.C.). In that case, Martland J. spoke for the majority at p. 848 [S.C.R.]:

> I do not think it is possible to define what constitutes a fair return upon the property of utilities in a manner applicable to all cases or that it is expedient to attempt to do so. It is a continuing obligation that rests upon such a utility to provide what the Commission regards as adequate service in supplying not only electricity but transportation and gas ... and to provide extensions to these services when, in the opinion of the Commission, such are necessary.

17 The Nova Scotia Supreme Court Appeal Division dealt with a similar issue in Re Dartmouth (1976), 17 N.S.R. (2d) 425 at 432 approving what had been said by the Nova Scotia Board of Commissioners:

> In determining a just and reasonable rate, the objective of the Board is to protect both the customer and utility, and to safeguard the overall public interest. The actual determination of rates is a complicated exercise. One must keep in mind the 'cost of service' concept as far as the utility is concerned. The concepts of 'value of service' and 'quality of service' are both of importance to the customers of the utility.

18 Reference was also made to the Nova Scotia appellate decision in P.U.C. v. N.S. Power Corp. (1976), 18 N.S.R. (2d) 692, 75 D.L.R. (3d) 72, and to the Newfoundland appellate decision in T.A.S. Communications Systems Ltd. v. Nfld. Tel. Co. (1983), 44 Nfld. & P.E.I.R. 114, 130 A.P.R. 114, 2 D.L.R. (4th) 647 (Nfld. C.A.).

19 In an American case, D.C. Transit System Inc. v. Washington Metro. Area Transit Comm., 466 F. 2d 394 (1972) (certiorari denied by the United States Supreme Court, 93 S. Ct. 688) the United States Court of Appeals, District of Columbia Circuit, reviewed a statute similar to the Public Utilities Board Act of Manitoba and said:

> ... the Commission's charge extends to the calibre of the carrier's operation and service as well as to the financial reasonableness of the fares it collects.

20 But, says the City of Brandon, while all that might be true in ordinary cases where the

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exhorted in this version of the constitution to "pass laws to correct abuses, prevent unjust discriminations and extortions in the rates of freight and passenger tariffs" and establish "reasonable maximum rates of charges" as well as "uniform rates on the same commodities as nearly as practicable."[1]

One of the proposed amendments of the railroad provisions would have been more precise in its outlawing certain railroad practices, such as their charging more for the long haul than the short haul, or charging more for the transportation in one direction than in the opposite direction.[2]

Speakers on both sides described the railroads' "unjust and ruinous rates" and the need to "prevent unjust discriminations and extortions."[3] An example of an "extortion" involved the railroads' charging high local rates for a portion of the interstate movement that occurred within Georgia. On a shipment of coffins from St. Louis, Mo. to Jesup, Ga., the freight charges were $14 from St. Louis to Savannah, Ga. and over $20 from Savannah to Jesup.[4] St. Louis is about 1,000 miles from Savannah; Jesup is 51 miles from Savannah.

On a shipment of cotton to Savannah a resident of Americus, Ga. complained that the freight charges were 10 cents per 100 pounds higher than from Albany, Ga., although Albany were 30 miles further from Savannah. He asked where was "the justice" of charging $1.25 per cotton bale from Americus to New York and only 80 cents from Albany to New York.[5]

A spokesman for the railroad interests conceded that the "convention should assert that railroads should not be unjust to any human being," but that in doing so should not follow the examples of Illinois, Indiana, and Pennsylvania, which had experienced labor strikes; rather, the members should get their opinions "nearer home."[6]

One speaker defined "unreasonable" as "exceeding the bounds of reason, exorbitant beyond appointed rules, enormous." He proceeded to show the first proposal described above was ambiguous, a "Delphic oracle" and a poor guide for future legislators:[7]

> Extortionate means characterized by extortion, oppression, taking by force.... When local freights become both unreasonable beyond reason, enormous, exorbitant, and also, extortionate, oppressive by reason of illegal exaction, then and not till then, shall it be the 'duty of the general assembly to pass such laws.' The next sentence [relating to maximum rates] is decidedly a la Evarts. You forget the beginning while wandering in the bewildering mazes of the middle, and before solving the sphinx-like riddles tangling the twaddle of the euphonious end.

He acknowledged that the intention was that the uniform rates shall be "just to the people" while at the same time "not destructive of the property or rights of the stockholders and creditors of the railroad companies."[8] He in contrast would "let the roads

[1] *Id.*, p. 385.
[2] *Ibid.*
[3] *Id.*, p. 391.
[4] *Id.* at 390.
[5] *Ibid.*
[6] *Id.*, p. 395. *See also* remarks of Mr. Screven, at p. 403.
[7] *Id.*, p. 459.
[8] *Ibid.*

fix their own rates, but not unjustly" and empower the legislature from time to time to establish maximum rates "to correct abuses and prevent unjust discrimination."[1]

The substitute offered by William M. Reese, lawyer and jurist, and agreed upon by the convention, read as follows:[2]

> The power and authority of regulating railroad freight and passenger tariffs, preventing unjust discriminations; and requiring reasonable and just rates of freight and passenger tariffs, are hereby conferred upon the general assembly, whose duty it shall be to pass laws, from time to time, to regulate freight and passenger tariffs, to prohibit unjust discriminations on the various railroads of this state, and to prohibit said roads from charging other than just and reasonable rates, and enforce the same by adequate penalties.

Mr. Nelson Tift, who was involved in railroad construction, and whose family was later embroiled in much rate litigation with the railroads,[3] defended the substitute as a proper compromise suggesting that the convention should not adopt more specific measures:[4]

> I agree with the gentlemen that railroads should be restrained within certain limits. They should not be permitted to do any injustice to, or extort money from, any individual or community of the state. Let them be limited to just and reasonable maximum rates for freight and passenger transportation.

A requirement for uniform rates would lead only to "the destruction of the railroad property of the state." Railroads must reduce rates to meet competition and in so doing should not be required thereafter to lower all rates to that level. In words that continue to resonate with current relevance, he urged:[5]

> You cannot destroy competition, and you cannot make the rates at competitive points uniform over the whole line, without destroying the property value of the roads.... Limit them by general laws to reasonable maximum rates for transportation, so as to prevent injustice or extortion, prevent them from combinations, and then leave them to free competition, which is the only natural, necessary and infallible regulator of trade and transportation. These in my judgment are the sum of our duties on this subject.

The convention would not settle for rates that would only be "reasonable"; they must also be "just." A "reasonable" rate could be justified logically in economic terms and yet work an injustice. The just rate would be judged by its effect on the shipping

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[1] *Id.*, p. 460. A defender of the first proposal thought there was little difference between these proposals—a difference "in the words only" (Matthews, *id.* at p. 461).

[2] Reese substitute for the original paragraph 1, section 2. There were 132 in favor of the substitute and only 14 opposed. *Id.* at 466. The quoted provision was included in the 1877 constitution as Art. IV, Sec. II, Para. 1.

[3] *See* H.H. Tift v. Southern Ry.Co., 10 ICC 548 (1905), sustained 138 Fed. 753, 148 Fed. 1021, 206 U.S. 428 (1907). H.H. Tift, the nephew of Nelson Tift, was a manufacturer of yellow pine lumber, a member of the Georgia Saw Mill Association, and otherwise active in short line railroad construction. *See* generally Northem, William F., Men of Mark in Georgia, Caldwell Publ., Atlanta, Ga. (1911).

[4] Small, Stenographic Report, *supra*, p. 393.

[5] *Id.* at 394.

public. The economic power of the railroads was recognized by all. An unjustly high rate would be a rate that had resulted from the railroads' exercise of their economic power to extort sums from the shippers. The word "extortion" was often juxtaposed with the word "injustice" in the Georgia debates as well as in the constitutional drafts of a regulatory provision. Thus the Georgia constitution of 1877 conferred on the legislature the duty "to prohibit said roads from charging other than just and reasonable rates."

All debate centered on the proposal for equal rates per mile throughout the state. The Reese substitute was introduced at the end of the debate as a compromise measure to protect both the railroads and the shipping public. It was destined to become the standard thereafter for much other legislation affecting railroads and utilities. Such was the commencement of just and reasonable as a maximum rate standard. Among Georgia historians, however, only General Toombs is remembered as the author of the power to regulate rail freight and passenger rates in Georgia, not Reese or Tift.[1]

Aftermath in the state of Georgia. In an act of 1879,[2] the Georgia Legislature enacted that if any railroad "shall charge, collect, demand or receive more than a fair and reasonable rate of toll or compensation for the transportation of passengers or freight," it would be "guilty of extortion." At the same time, it provided for the appointment of three railroad commissioners, and authorized and required them to make "a schedule of just and reasonable rates of charges for the transportation of passengers and freights and cars on each of said railroads," and to revise them "as often as circumstances may require." The jurisdiction of this commission was extended in 1907 to include docks, wharves, terminal companies, cotton compress companies, railroad terminals, telephone and telegraph companies, street railroads, gas, light and power companies; and in 1931 to cover motor vehicle transportation. Its name was changed to the Public Service Commission in 1922.[3]

When a stockholder of an affected railroad attacked the creation of the railroad commission in a federal court in Georgia, the court sustained the law and refused to reset the rates established by the Georgia commission.[4] The court held that the legislature itself was not required to set rates:[5]

> It has, in performance of this [constitutional] duty, declared that the rates charged by the railroad companies should be just and reasonable, and appointed a commission to fix the maximum of just and reasonable rates,

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[1] *See* Cooper, Walter G., The Story of Georgia, vol. III, The Am. Hist. Soc., Inc., N.Y., p. 261 (1938). Toombs, another author claims, "had come to the Convention primarily to fight the railroads," and he had made the railroad topic "under the old Constitution his special study." Ware, Ethel K., A Constitutional History of Georgia, Columb. Univ. Press, N.Y., p. 163 (1947).

[2] "An act to provide for the regulation of railroad freight and passenger tariffs," etc., Georgia Laws, Title 12, No. 269, approved Oct. 14, 1879. The preamble referred to the "just and reasonable" phrase of the 1877 constitution; section III referred to a "fair and reasonable rate"; section V referred to "reasonable and just rates"; section VIII referred once again to "just and reasonable rates."

[3] Job, Richard C., Government Manual of Georgia, State Planning Board, p. 35 (1938). The early decisions and case files of the Georgia Railroad Commission have not been found. Searches at the State Law Library and at the State Archives in Atlanta as well as an inquiry at the University of Georgia in Athens, Ga., failed to uncover them.

[4] Tilley v. Savannah, Florida & Western R.Co., 5 Fed. 641 (1881) (opinion by Cir. J. Woods).

[5] *Id.* at 655-56.

decisional law from other jurisdictions provide "persuasive authority by analogy."[1] In addition much of the federal rate regulation originated in the statutes conferring authority on the I.C.C. to regulate common carriers; the parallels among later statutes have been noted on judicial review of agency work outside the I.C.C.[2]

Precedent is relevant on the basis of the broader legal principle that "the starting point" for just and reasonable rates is any long-standing business practice that has arisen with respect to such rates. "A change cannot be made without either a reasoned explanation or a finding that such a practice is unjust and unreasonable."[3]

Under the federal A.P.A., agency rules must be published in the *Federal Register*, and agency decisions must either be made available to the public for inspection and copying or be "promptly published and copies offered for sale." A final order, opinion, or statement of policy may not be cited as precedent against a party other than an agency unless it has been made available or published, or the party has actual and timely notice of its terms.[4]

Of course, an agency's official views are expressed in more than its official, publicly reported decisions. It will typically issue a steady stream of orders, press releases, letters, letter-orders, and accounting letters.[5] These less publicly known or available positions of an agency are not binding on persons other than those with actual or constructive notice of their content.[6]

The binding effect of precedent is also manifest in the principle that all similarly situated regulated entities should be treated alike. An agency will attempt to apply its cost terms and definitions uniformly to the various utilities that are subject to its rules, whether or not the rules and practices are formally codified.[7]

A different rule of conduct should not be applied retroactively to one company without applying the same rule to all like companies. If the regulator applies a new standard to one and not to all similar companies it is subject to a charge of "unfair discrimination."[8]

An agency may decide to exempt a line of cases from its precedential holdings, especially where a speedy decision is needed or lack of experience limits their reliability. For example, the F.E.R.C. has stated that incremental rates that are adopted as startup or initial rates for a service will establish no principles or precedents, and will be adopted without prejudice to the rights of parties to argue for alternative rates in future proceedings after the proposed facilities have been placed in service.[9]

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[1] Re New England Tel. and Teleg.Co. d/b/a NYNEX, 160 PUR4th 95, 111 (Mass.DPU, 1995), citing Commonwealth Elec.Co. v. Dept. of Pub. Utils., 397 Mass. 361, 366 note 3, 491 N.E.2d 1035 (1986), cert. denied 481 U.S. 1036 (1987); *but see* Re Mass.Elec.Co., 164 PUR4th 393, 434 (Mass.DPU, 1995) (referring to "the limited precedential value of decisions in other jurisdictions").

[2] *See* Consolo v. F.M.C., 383 U.S. 607 (1966); AT&T v. F.C.C., 487 F.2d 865, 879 (2d Cir. 1973).

[3] Re Southern Nat.Gas Co., 51 FERC ¶61,296, 113 PUR4th 354, 358 (1990).

[4] 5 U.S.C. §552(a).

[5] *See, e.g.*, Re Wisconsin Bell, Inc., 113 PUR4th 373, 379, 381 (Wisc.PSC, 1990).

[6] Federal agency documents other than final decisions may be cited as precedent only if indexed, made available to the public, and the affected party has "actual and timely notice of the terms thereof" (5 U.S.C. §552(a)(2)).

[7] Re Baltimore Gas and Elec.Co., 143 PUR4th 215, 235 (Md.PSC, 1993); Re Illinois Power Co., 117 PUR4th 418, 423-24 (Ill.CC, 1990).

[8] *See* Blue Cross & Blue Shield of Del. v. Elliott, 479 A.2d 843, 850-51 (Del.Super. 1984).

[9] Re Tennessee Gas Pipeline Co., 51 FERC ¶61,113, 112 PUR4th 464, 474, 487 (1990).

GENERAL PRINCIPLES. Cost of service encompasses all cash and non-cash outlays for the operations of the regulated business. It is sometimes referred to as the company's "above-the-line" expenses. It excludes the profit element, although even this, as we shall see in later pages,[1] is generally allowed as a putative cost—the market cost of supplying capital for investment in the enterprise. Before reaching any question of "something more,"[2] we will first explore how the regulator fulfills the obligation to cover operating costs.[3] In their absence, there can be no ascertainment of a reasonable profit; additional profits will simply be hidden among the unascertained costs.

[1] *See* p. 593

[2] We borrow a phrase from the Court of Appeals. *See* p. 589.

[3] Depreciation of property is a legitimate cost of service, but it merits separate study, and will be the subject of a separate section. *See* p. 485

Computation and allocation of costs of service lies at the heart of the tasks of a regulatory agency's administration of the just and reasonable standard. As the Supreme Court early held, a rate that is below the cost of the service is "intrinsically just and reasonable."[1] The "long and often judicially approved practice of basing rates on cost carries a substantial presumption of validity which places a heavy burden on those who would refute it."[2]

Among the questions that continually vex the regulatory commissions are, a) what costs should be covered by the rates for a particular service; b) what procedures and standards apply to identify those costs; and c) how should the costing of services relate to the required accounting and reporting by the regulated company?

The courts acknowledge that cost allocation is not an exact science, and that generally the legislature leaves the choice of methods to perform the allocation to the judgment of the rate-setting agency.[3] Nevertheless, there are numerous, settled principles at work here, that bear directly on the way an agency can and does find and use costs of service in its rate cases.

Jurisdictional v. non-jurisdictional. Like the separation of revenues,[4] an initial separation of costs of service must precede a rate proceeding. Many regulated companies serve in more than one state, and costs must be allocated to the affected jurisdictions. If a company is engaged in both intrastate and interstate business, the costs incurred in its interstate business may be subject to the jurisdiction of a federal regulatory agency (in which case the federally approved separation rules take precedence over state mandated separation).

Interstate costs are not necessarily indicative of the intrastate costs for an individual state. The failure to find state-specific costs is a failure to establish the rates on substantial evidence, that is, a failure to show a reasonable relationship between rates and costs of service.[5]

The F.C.C. separation rules[6] for telecommunications companies not only establish the relative assignment of their costs as between intrastate and interstate business, but also provide an accounting framework that is widely accepted in the states for such companies. The California commission, among others, follows the F.C.C. cost allocations in its regulation of intrastate LEC services, except for two basic differences.[7]

Typically jurisdictional services are separated from non-jurisdictional through a series of cost and revenue allocations. The F.C.C. rules follow the accountant's assignment of direct and indirect costs.[8] When an allocator cannot be found, a "general allocator" must be used based on the ratio of all expenses directly assigned or

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[1] I.C.C. v. Chicago, B.& Q.R.Co., 186 U.S. 320, 339 (1902).

[2] Shell Oil Co. v. F.P.C., 520 F.2d 1061, 1083-84 (5th Cir. 1975).

[3] National Ass'n of Greeting Card Pubs. v. U.S. Postal Service, 462 U.S. 810, 825-26 (1983), and cases there cited

[4] *See* p. 241, *supra*.

[5] Telecommunications Resellers v. Pub.Svc.Comm'n, 747 P.2d 1029, 1031 (Utah 1987).

[6] 47 CFR Part 64.

[7] Re Regulatory Frameworks for LECs, 125 PUR4th 260, 265-66 (Cal.PUC, 1991). California follows the F.C.C. rules except for omission of tariff imputation mandated by the F.C.C. and plant allocation based on three year forecasted plant usage.

[8] 47 CFR Part 64.

attributed to regulated and non-regulated activities. For central office equipment and outside plant investment, the separation is based on the peak ratio of projected non-regulated usage during the next three calendar years.

The F.C.C. enforces its separation rules through two major measures. First, each carrier must file a cost allocation manual showing its affiliates, cost apportionment methods, and time reporting procedures.[1] Second, carriers must not only update their manuals at least quarterly, but also provide an annual independent audit certifying that the annual report filed with the F.C.C. is consistent with both the manual and with commission rules and regulations.[2] The regulated company thereby is required to participate actively in the ongoing enforcement activity.

Separation rules must also be fashioned for other regulated businesses, such as the insurance business. The California insurance commission by rule prescribes the allocation factors that an insurance company shall use to allocate basic experience data to that state, where such data are maintained only on a multi-state basis or the California data are not reliable (or "credible"). The commissioner decides whether the California-specific data are reliable upon considering,[3]

> whether the data were recorded by persons and under circumstances likely to produce accurate data, whether the data were relied upon by the party in its business, and whether the data are consistent with other data.

Fact finding v. wishful thinking. Expenses, as the Court of Appeals has found, including in a broad sense operating expenses, depreciation, and taxes, are "facts ... to be ascertained, not created, by the regulatory authorities"; without their proper determination the allowance of a return, "being an amount over and above expenses, would be a farce."[4]

An increase in volume does not by itself without further analysis imply across-the-board increases in operating costs. The California commission rejects a cause and effect relation between customer growth and utility administrative and general (A&G) expense. It suggests that if both are growing other factors may be responsible; hence the connection, if any, is at best "flimsy."[5]

An agency is justifiably skeptical of budget cost estimates as a basis for ratemaking. It will rely on test period results subject to adjustment for known or reasonably expected changes.[6] The budget process is subject to assumptions that are not necessarily known or measurable.[7]

The study of the operating costs of the regulated business should be the regulator's number one priority. An agency makes a serious mistake when it fails to search for cost causation. I shall later single out the C.A.B.'s lack of cost analysis as a failing of that

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[1] 47 CFR §64.903.
[2] 47 CFR §64.904.
[3] Cal.Ins.Regs., Title 10, §2643.6(a).
[4] Mississippi River Fuel Corp. v. F.P.C., 163 F.2d 433, 437 (D.C.Cir. 1947).
[5] Re Southern Calif.Edison Co., 130 PUR4th 97, 119-20 (Cal.PUC, 1991).
[6] *See* p. 141, *infra*.
[7] Re Montana Power Co., 125 PUR4th 30, 42 (Mont.PSC, 1991).

"USED AND USEFUL": AUTOPSY OF A RATEMAKING POLICY

*James J. Hoecker**

The "used and useful" principle emerged from the primordial ooze of the public regulation of private enterprise and, in the epoch of "fair value" ratemaking, entered common regulatory parlance. It has become "a bedrock principle of utility regulation."[1] Compared to the particularities of modern ratemaking, such as marginal cost pricing, discounted cash flow analyses, cost classification and allocation techniques, and econometric modeling, it has a certain immutable friendliness and clarity. It seems beyond cavil that "[t]he rate base on which a return may be earned is the amount of property used and useful, at the time of the rate inquiry, in rendering a designated utility service. If the original cost or prudent investment concept is applied, this figure normally may be taken from the utility's books."[2]

Why then should anyone intimate, as does this article, that "used and useful" is moribund? Or, for that matter, that it even requires scholarly exposition? The recent wrangling within the U.S. Court of Appeals for the D.C. Circuit over application of used and useful to a cancelled nuclear plant suggests that the concept is alive, if not well. That court struggled mightily with the principle in three successive *Jersey Central Power & Light Co. v. FERC* decisions[3] which highlight how troublesome its various meanings and applications have become during the era of end result ratemaking. In the process, the court examined used and useful for one of the few times in the ninety-year history of the concept.

This article examines the evolution of the used and useful concept, the confusion it has engendered, and its current applications and misapplications, focusing on the ratemaking practices of the Federal Power Commission (FPC)

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1. Kentucky Utils. Co. v. FERC, 760 F.2d 1321, 1324 n.4 (D.C. Cir. 1985).

2. 1 PRIEST, PRINCIPLES OF PUBLIC UTILITY REGULATION 139-40 (1969).

3. Jersey Central Power & Light Co. v. FERC, 730 F.2d 816 (D.C. Cir. 1984) [hereinafter *Jersey Central I*] (unanimously affirming the Commission's summary denial of Jersey Central Power & Light's (JCP&L) application to recover $397 million prudently invested in a later-abandoned nuclear plant); Jersey Central Power & Light Co. v. FERC, 768 F.2d 1500 (D.C. Cir. 1985) [hereinafter *Jersey Central II*] (remanding the case because of the Commission's failure to explain how its summary application of its used and useful rule affected the overall end result of the rate; later vacated in favor of *en banc* review in Jersey Central Power & Light v. FERC, 776 F.2d 364 (1985)); Jersey Central Power & Light v. FERC, 810 F.2d 1168 (D.C. Cir. 1987) [hereinafter *Jersey Central III*] (vacating and remanding the Commission's order for failure to inquire under FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944) (*Hope* or *Hope Natural Gas*), whether a rate that excludes recovery of the investment in the abandoned plant is just and reasonable in light of its effect on the investors in the financially-distressed utility). All majority opinions are by Judge Bork.

and its successor, the Federal Energy Regulatory Commission (FERC), both of which have been scarcely less taciturn than the courts in discussing the idea.

I. USED AND USEFUL BEFORE *HOPE*

Long before regulatory bodies or the courts plumbed the methodological niceties of ratemaking, the idea evolved that the public has certain rights in the private property it used for its own benefit. Going back to the regulation of ferry boats and port facilities under King James I of England, courts distinguished between those goods and services solely within the ambit of private property rights and those "affected with a public interest."[4] In *Munn v. Illinois*,[5] the Supreme Court set out the historic theory underlying public regulation of private property:

> Property does become clothed with a public interest when used in a manner to make it of public consequence, and affect the community at large. When, therefore, one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use, and must submit to be controlled by the public for the common good, to the extent of the interest he has thus created. He may withdraw his grant by discontinuing the use, but, so long as he maintains the use, he must submit to the control.[6]

The issue inherent in such a formulation is how best to distinguish activities clothed in public interest[7] from those within what was jurisprudentially called the *juris privati*. Whether the public use or convenience is construed broadly or narrowly determines largely the protagonist's relative market position as a

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4. Lord Hale, *De Jure Maris & Brachiorum Ejusdem*, in 1 HARG. LAW TRACTS 6-8 (1787).

5. Munn v. Illinois, 94 U.S. 113 (1876).

6. *Id.* at 126.

7. Various tests are suggested for determining whether an enterprise operates as a public utility, *i.e.*, in the public interest. Economic tests pertain to natural limitations on the source of supply, the conditions under which a product is supplied (*e.g.*, natural monopoly considerations), the scarcity of advantageous sites, time limitations on the customer, or perhaps conditions that deter competition. *See* M. GLAESER, OUTLINES OF PUBLIC UTILITY ECONOMICS, 172-79 (1931). A further legal distinction is drawn in those cases where a private company operated as an agent of the state, exercising its right of eminent domain. Public control arises from the use of public power. Olcott v. The Supervisors, 83 U.S. 678, 695 (1873). Later, in the regulatory context, Justice Brandeis stated that an investor's "company is the substitute for the State in the performance of a public service . . . ." Missouri *ex rel.* Southwestern Bell Tel. Co. v. Public Serv. Comm'n, 262 U.S. 276, 291 (1923) (Brandeis and Holmes, JJ., dissenting) [hereinafter *Southwestern Bell Tel.*]. *But cf.* Jersey Central III, 810 F.2d at 1189 (Starr, J. concurring) ("The utility is not a servant to the state; it is a for-profit enterprise which incurs legal obligations in exchange for state-conferred benefits.").

Companies may naturally have resisted classification of all or part of their activities as devoted to a public use because of the limitations which government might place on their earning power. However, as regulatory law developed, companies became more completely devoted to public uses (even overtly supportive of regulation by the state) and increasingly subject to some form of price-fixing by public institutions. Under such modern circumstances, earnings might logically be maximized by arguing either that the assets of the company determined to be in the public service are of higher value, or that a greater proportion of the companies' total assets or expenditures are dedicated to a public use. The final argument is the crux of the historic "used and useful" debate between regulated industries and regulators. Revisionist theories of regulation suggest that business insisted on regulation in several instances, thereby obviating the need to seek the value of private property in commercial markets. G. KOLKO, THE TRIUMPH OF CONSERVATION: A REINTERPRETATION OF AMERICAN HISTORY, 1900-1916 (1963).

producer or consumer, the economic climate (*i.e.*, the prospect of relative increases or decreases in the value of property due to inflation or deflation), and finally the prevailing means of measuring the worth of utility properties.

The historic distinction between what is and what is not employed or devoted to a public use, in other words what is "clothed with a public interest" so as to warrant economic constraint by society, relates to the distinction in ratemaking theory between what is and what is not used and useful to the public service. Both are fundamentally considerations of equity between the interests of the providers and the consumers of a service.[8] Accordingly, regulation by the state is limited both in its control of private property and the benefits it may bestow on the public by the extent to which private activity or property is colored and thereby governed by the public interest. The legal analogy used by the Court in 1894 as a means of explaining the "taking" of private property for public use in return for just compensation was, of course, the law of eminent domain.[9] Not until *Smyth v. Ames*,[10] however, did the Supreme Court formulate a coherent test of the extent to which regulated companies were protected from legislative expropriation on behalf of the public, that is, what compensation was due. Ascertaining how much compensation a utility deserves begins with deciding what property is truly committed to public service.

Before *Smyth v. Ames*, regulatory agencies were already excluding from "the valuation," *i.e.*, the rate base, property that was not actually employed in the utility function.[11] The "fair value" cases which followed *Smyth v. Ames*, and which arose from state and local regulatory actions, adopted the used and useful principle.[12] Ratemaking treatises written from the "fair value" standpoint used the term but analyzed only the valuation portion of the theory.[13]

8. *But see* Drobak, *From Turnpike to Nuclear Power: The Constitutional Limits on Utility Rate Regulation*, 65 B.U.L. REV. 65 (1985). Drobak found that, since *Hope*, the Constitution permits investors' financial interests to be readily subordinated to those of the public. *Id.* at 97. However, "the extreme financial harm that commissions may impose on utility investors without violating the Constitution" at some point results in an unconstitutional confiscation of capital. *Id.* at 124. The view that the used and useful test carries out this balance in favor of the public and against investors, *id.* at 94, is adopted by the concurring opinion in *Jersey Central III*, 810 F.2d at 1180-81. *See infra* Section III.

9. Reagan v. Farmers' Loan & Trust Co., 154 U.S. 362, 410 (1894).

10. Smyth v. Ames, 169 U.S. 466 (1898).

11. San Diego Water Co. v. City of San Diego, 118 Cal. 556, 50 P. 633 (1897) (excluding property "now not available for present use"); Capital City Gaslight Co. v. City of Des Moines, 72 F. 829 (C.C.S.D. Iowa 1896); Covington & Lexington Turnpike Road Co. v. Sandford, 164 U.S. 578, 596-98 (1896).

12. *See, e.g.*, San Diego Land & Town Co. v. National City, 174 U.S. 739, 756 (1899) ("What the company is entitled to demand, in order that it may have just compensation, is a fair return upon the reasonable value of the property at the time it is being used for the public."); Willcox v. Consolidated Gas Co., 212 U.S. 19, 41 (1909) ("There must be a fair return upon the reasonable value of the property at the time it is being used for the public."); Cumberland Tel. & Tel. Co. v. City of Louisville, 187 F. 637, 642, 646-48 (C.C.W.D. Ky. 1911), *rev'd*, 225 U.S. 430 (1911), (referring to a return on property "at the time it is being used for the public"); Minnesota Rate Cases, 230 U.S. 352, 354-55 (1913) ("The ratemaking power is legislative power and necessarily implies a range of legislative discretion . . . . The basis of calculation is the fair value of the property used for the convenience of the public."); Lake Hemet Water Co. 1917A Pub. Util. Rep. (PUR) 468, 477-78 (Cal. R.R. Comm'n 1917) (deducting from the valuation of an overbuilt system the investment in excess capacity).

13. H. FLOY, FAIR VALUE FOR RATE-MAKING 54-99 (1916) ("Present value means the 'here and

Despite this off-handed treatment of "used and useful," the valuation of "fair value" theorists held closely to what may be termed an immediate use doctrine. The New York Public Service Commission articulated the standard:

> Consumers should not pay in rates for property not presently concerned in the service rendered, unless—
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> (1) Conditions exist pointing to its immediate future use; or
>
> (2) Unless the property is such that it should be maintained for reasonable emergency or substitute service; and in studying these two exceptions the economic factor should be carefully considered.[14]

The used and useful principle fits comfortably into fair value theory as a kind of method of inventory of currently operative items of physical plant. Moreover, recurring references to the principle in the case law prior to *Hope* served to associate used and useful with the liturgy of fair value ratemaking.

In 1898, when the Supreme Court found in *Smyth v. Ames*[15] that a Nebraska law fixing unreasonably low freight rates violated the Fourteenth Amendment, public utility regulation was a local affair with an unmistakably populist and experimental air to it. Ratemaking methodologies were only beginning to coalesce around a consistent framework of constitutional, economic, and accounting principles. Commentators have customarily viewed the case to some degree as the first to formulate a consistent approach to ratemaking matters, notable with respect to rate base valuation. Justice Harlan's oft-cited holding in *Smyth v. Ames* influenced the tenor and course of ratemaking policy for two generations:

> We hold . . . that the basis of all calculation as to the reasonableness of rates to be charged by a corporation maintaining a highway under legislative sanction must be the *fair value* of the property being *used by it for the convenience of the public* . . . . What the company is entitled to ask is a fair return upon the value of that which it *employs for the public convenience*.[16]

This required, among other things, that the rate base (net value of investment in earning assets) must be "valuated" at its present market cost or its reproduction cost (the Court specified several factors to be considered) and consist of property devoted to a public use.[17] The Court thereby set forth the idea that the only public utility property eligible to earn a return must be used in the public service.

Smyth v. Ames profoundly affected utility regulation until the 1940s. Its bold declaration of a ratemaking standard that would protect utility investors

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now' value of the property used, useful, or reasonably required for the service being rendered." *Id.* at 70); *see also* C. GRUNSKY, VALUATION, DEPRECIATION AND RATE-BASE 17-19, 150-62 (1922).

14. Elmira Water, Light & R.R., 1922D Pub. Util. Rep. (PUR) 231, 238 (N.Y. Pub. Serv. Comm'n 1922).

15. "The case . . . climaxed two decades of decisions in which the court gradually took unto itself the power of reviewing the reasonableness of rate regulation." Barron, *The Evolution of* Smyth v. Ames, 28 VA. L. REV. 761, 762 (1942).

16. *Smyth*, 169 U.S. at 546-47 (emphasis added).

17. *Id.* Justice Harlan's affirmance of Circuit Judge (later Justice) David Brewer is thought generally to be a restatement of the latter's opinion below. Brewer's ideas reflected a close identification of rate regulation with the law of eminent domain and thus held that property *taken* for public purposes must be paid for in terms of its actual value. Barron, *supra* note 15, at 791. Ames v. Union Pac. Ry. Co., 64 F. 165, 177 (C.C.D. Neb. 1894).