PUBLIC UTILITIES BOARD

WRITTEN FINAL ARGUMENT OF MANITOBA HYDRO

WITH RESPECT TO MANITOBA HYDRO'S
2023/24 & 2024/25 GENERAL RATE APPLICATION

June 19, 2023

Manitoba Hydro
energy for life

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List of Abbreviations and Acronyms

A&RL	Area & Roadway Lighting Class
AGC	Automation Generation Control
ALG	Average Life Group
AMC	Assembly of Manitoba Chiefs
AMCL	Asset Management Company Limited
AMI	Advanced Metering Infrastructure
ASL	Average Service Life
BCG	Boston Consulting Group
BCUC	British Columbia Utilities Commission
BOC	Business Operating Capital
BTM	Behind-the-meter
CAAP	Customer Arrears Assistance Plan
CCA	Cloud Computing Arrangement
CCGAA	The Crown Corporation Governance and Accountability Act
CEATI	the Centre for Energy Advancement through Technological Innovation
CGAAP	Canadian Generally Accepted Accounting Principles
CIC	Capital Investment Concept
CIJ	Capital Investment Justification
COS	Cost of Service
COSR	Cost of Service Methodology Review
COSS	Cost of Service Study
CP	Confident Peak
CPI	Consumer Price Index
CRP	Curtailable Rate Program
CRSG	Contingency Reserve Sharing Group
CSI	Commercially Sensitive Information
CVF	Corporate Value Framework
DBRS	Dominion Bond Rating Service
DEA	Daymark Energy Advisors
DSM	Demand-Side Management
EAR	External Asynchronous Resources
ED	Exposure Draft
ELG	Equal Life Group
ERM	Enterprise Risk Management

ERP	Enterprise Resource Planning
FTE	Full Time Equivalent
G&T	Generation and Transmission
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GRA	General Rate Application
GS	General Service
GSL	General Service Large
GSM	General Service Medium
GSPRO	Generation System Simulation Planning and Resource Optimization
GSS	General Service Small
GSSD	General Service Demand
GSSND	General Service Small Non-Demand
GWI	General Wage Increase
HERMES	Hydro-Electric Reservoir Management and Estimation System
HVDC	High Voltage Direct Current
IAS	International Accounting Standards
IEC	Independent Energy Consultant
IFRS	International Financial Reporting Standards
IPM	Integrated Pole Maintenance
IR	Information Request
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IRRP	Integrated Rate Risk Profile
IT	Information technology Systems
kW	Kilowatt
kWh	Kilowatt hour
LCOSS	Lighting Cost of Service Study
LED	Light Emitting Diode
MFR	Minimum Filing Requirement
MH	Manitoba Hydro
MHEB	Manitoba Hydro Electric Board
MIPUG	Manitoba Industrial Power Users Group
MISO	Midcontinent Independent System Operator
MW	Megawatt

MWh	Megawatt-hour
NARUC	The National Association of Regulatory Utility Commissioners
NBF	National Bank Financial
NCP	Non-coincident Peak
NER	Net Export Revenue
NERC	North American Electric Reliability Council
NSP	Northern States Power
NUG	Non-utility Generation
O&A	Operating and Administrative
O&M	Operations and Maintenance
OBPIF	Operational Physically Based Inflow Forecasting Framework
PBIF	Physically Based Inflow Forecasting
PCOSS	Prospective Cost of Service Study
PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PUB	Public Utilities Board
PV	Photovoltaic
RCC	Revenue to Cost Coverage
RDA	Rate Design Application
RM	Risk Management
S&P	Standard & Poor's
SAIDI	System Average Interruption Distribution Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SAP ECC	SAP ERP Central Component
SEP	Surplus Energy Program
SLF	System Load Factor
SPLASH	Simulation Program for Long-term Analysis of System Hydraulics
T-SAFI	Transmission System Average Interruption Frequency Index
T-SAIDI	Transmission System Average Interruption Distribution Index
URA	Uniform Rate Adjustment
VDP	Voluntary Departure Program
ZOR	Zone of Reasonableness

1. REQUESTED APPROVALS IN MANITOBA HYDRO'S APPLICATION

1.1. Background and Overview of the Approvals Sought

On November 15, 2021, Manitoba Hydro filed its 2021/22 Interim Rate Application seeking approval of rate schedules incorporating an overall increase in General Consumers Revenue of 5% effective January 1, 2022 to address the financial impacts of the drought, as well as the significant increase in revenue requirement associated with the carrying costs on the major capital project that had been placed in-service. In Order 137/21, the PUB varied the request and approved a 3.6% interim rate increase effective January 1, 2022. On January 26, 2022, the PUB issued Order 9/22 directing Manitoba Hydro to file a General Rate Application ("GRA") by November 15, 2022, to confirm the 2021/22 interim rate increase and seek rates for future years if it so chose.

In compliance with the direction by the PUB, on November 15, 2022, Manitoba Hydro filed its 2023/24 & 2024/25 GRA, seeking final approval of the 3.6% interim rate increase effective January 1, 2022, and approval of an overall general revenue increase of 3.5% effective September 1, 2023, and a further overall general revenue increase of 3.5% effective April 1, 2024.

On November 23, 2022, the Province of Manitoba announced that it would be reducing the provincial debt guarantee and water rental fee paid by Manitoba Hydro by 50%, retroactive to April 1, 2022. In response, on November 29, 2022, Manitoba Hydro advised the PUB that the announcement would have a material impact on its finances. Consequently, on December 9, 2022, Manitoba Hydro amended its GRA by commensurately reducing the requested rate increases from 3.5% to 2% in 2023/24 and 2024/25.

The GRA seeks final approval of the 3.6% interim rate increase effective January 1, 2022 granted in in Orders 137/21 and 140/21 and final approval of rate schedules reflecting overall revenue increase of 2% effective September 1, 2023, and 2% effective April 1, 2024, sufficient to generate additional revenues of $24 million in 2023/24 and $38 million in 2024/25.

In addition, Manitoba Hydro requests approval of the following:

- Final approval of the Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class approved on an interim basis in Order 150/20;
- Approval of additional Area and Roadway Lighting rates as set out in Tab 8, Appendix 8.4 of this GRA;
- Final approval of all Surplus Energy Program ("SEP") and Curtailable Rate Program ("CRP") interim ex parte Orders as set out in Tab 9, Appendix 9.1 of this GRA as well as any additional SEP and CRP interim ex parte Orders issued subsequent to the filing of the Application and prior to the PUB's Order in this matter;
- Endorsement of modifications to the Terms and Conditions of Service of the SEP and the CRP as set out in Tab 8, Appendix 8.13 and 8.14, respectively, of this GRA;
- Endorsement of change in the cost allocation methodology for the LED Roadway Lighting Conversion Program (Demand Side Management) costs;
- Approval to remove the Cooking and Heating Rates (Standard and Seasonal) from the Rate schedule which are no longer in use by Manitoba Hydro as set out in Tab 8, Appendix 8.4 and 8.7 of this GRA; and
- Endorsement of changes to existing deferral accounts and the establishment and amortization of new regulatory deferral accounts, as discussed in Tab 4, Appendix 4.3 (Amended) of this GRA and summarized as follows:

    a) The endorsement of the established Keeyask in-service deferral account and the approval of the amortization period;
    b) The establishment and amortization of a new regulatory deferral for SAP S/4HANA cloud computing arrangements;
    c) The determination of a depreciation methodology for rate setting purposes and establishment and amortization of related deferral accounts;
    d) The determination of an amortization period for the Major Capital Projects deferral account; and
    e) The write off of the Demand Side Management Deferral debit and credit accounts.

2. STRATEGY 2040 & BUSINESS MODEL

The evolving energy landscape is changing rapidly, largely due to external forces and changes in customer demands. Consistent with Manitoba Hydro's perspective, the period of rapid transition currently taking place was noted in Daymark's evidence.[1] Coupled with

[1] DEA-2, Daymark Independent Expert Consultant Report, page 24.

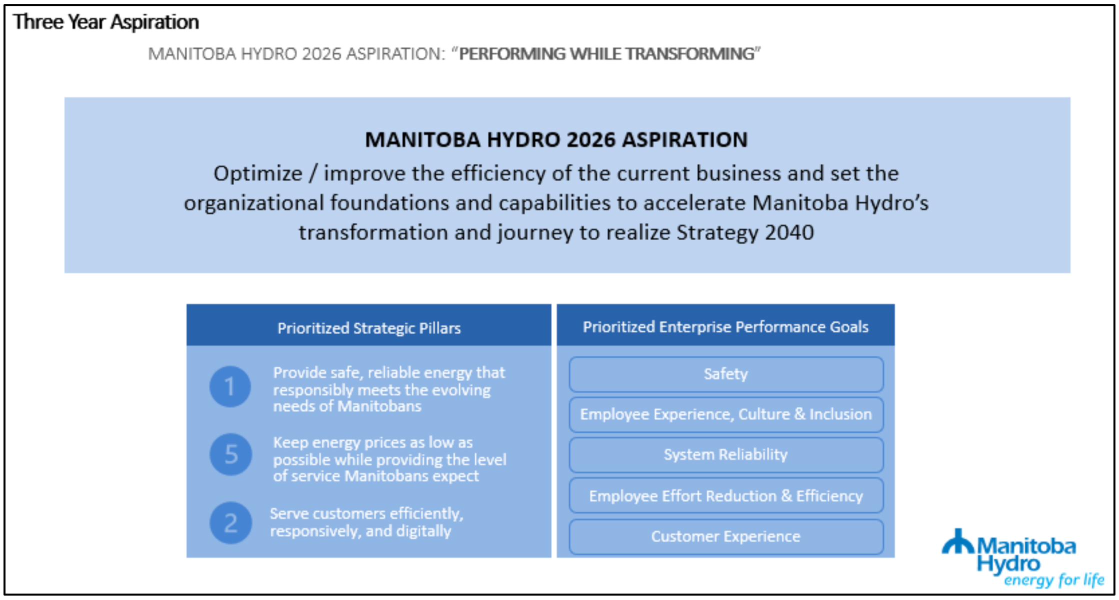
Federal energy and climate policies and new regulation, Manitoba Hydro is taking prudent steps to prepare for the future. Left unmanaged, these changes can have a negative impact on customers, the long-term health of Manitoba Hydro, and the province. It would be imprudent, as Mr. Rainkie suggests,[2] to wait until Manitoba's energy policy and Manitoba Hydro's Integrated Resource Plan ("IRP") are finalized before embarking on a plan to address these significant changes to the energy industry. With Strategy 2040, Manitoba Hydro is planning for these changes and working towards them. As the future will be very different than the past, Strategy 2040 will enable Manitoba Hydro to manage these challenges, to minimize risks, and to take proactive steps to manage supply and demand and maximize the value of existing assets while minimizing costs.

Essential to Strategy 2040 is Manitoba Hydro's commitment to continuing to provide safe, clean, reliable energy, operating as efficiently and effectively as possible, while being responsive to customers and preparing for changes in the energy landscape that are already occurring. Within the long-term direction of Strategy 2040, Manitoba Hydro is prioritizing its portfolio of initiatives, focusing and setting direction for the next three years through its three-year aspiration, or "performing while transforming." This near-term view helps Manitoba Hydro make choices today and prioritize to ensure it can plan for the future effectively while serving its customers today.

Through prioritization, Manitoba Hydro is better situated to manage risks. Manitoba Hydro plans to utilize its limited resources more effectively to achieve the most important goals. In the near-term view, Manitoba Hydro is prioritizing Pillars 1, 5 and 2 of Strategy 2040 as depicted in the table below.[3] Developing the IRP and continuing to support government policy advancement, such as energy policy, are key near-term strategic initiatives in Strategy 2040.

[2] CC-7, Revenue Requirement Evidence prepared by Darren Rainkie, April 3, 2023, page 18.
[3] MH-28, Manitoba Hydro Policy Panel Direct Evidence Presentation, slide 8.

Figure 1



It is also important to note that Strategy 2040 is flexible and adaptable and will continue to evolve as the energy landscape evolves.

Mr. Rainkie takes a contrary perspective and suggests that Strategy 2040 is premature.[4] Mr. Rainkie advocates for a 'wait and see approach' which inherently carries the risk of being unprepared. A 'wait and see approach' for Manitoba Hydro while the energy industry is transforming is not a plan. Throughout the hearing, Manitoba Hydro has demonstrated this risk is not acceptable.

Mr. Rainkie also suggests that Manitoba Hydro ought to have taken a 'wait and see approach' to its business model realignment.[5] Traditionally, Manitoba Hydro was organized around functional segments (e.g. Generation, Transmission, Distribution); it has now adopted a more integrated approach that aligns the organization around operations, managing assets, providing customer service, as well as supporting business units. Manitoba Hydro is evolving its approach toward Customer Centricity, Asset Management, Work Management, Project Delivery, Transformation, Digital, Enterprise Risk Management and Enterprise Planning. The business model realignment is being undertaken not only to position Manitoba Hydro to respond to the evolving energy

[4] CC-7, Revenue Requirement Evidence prepared by Darren Rainkie, April 3, 2023, page 18.
[5] CC-7, Revenue Requirement Evidence prepared by Darren Rainkie, April 3, 2023, page 20.

landscape, but also to build upon core foundational capabilities that will improve the corporation's overall efficiency and effectiveness while drawing from industry best practices.

The proposed rate increases in this Application form part of a plan that will ensure Manitoba Hydro can continue to meet customer expectations with respect to affordable, clean energy and safe, reliable service and become a financially healthy utility that Manitobans can continue to rely on for their energy needs now and in the future. Manitoba Hydro submits that its proposed rate increases are just, reasonable, and in the best interests of its customers and the public interest.

3. RATE PATH & RATE PATH PRIORITIES

Bill 36, *The Manitoba Hydro Amendment and Public Utilities Board Amendment Act*[6] (the "Act"), was enacted when it received royal assent on November 3, 2022. At this time, the Act, among other things, amended *The Manitoba Hydro Act.* While the transitional provision of the Act establishes that the existing legislative framework[7] continues to apply to the determination of rates for the retail supply of power under *The Manitoba Hydro Act* until April 1, 2025, the Act enshrines the government's policy as it relates to electricity rates in Manitoba.

3.1. The Guiding Priorities of the Rate Path

As discussed in Tab 3 (Amended) of the Application, when establishing its projected rate path, Manitoba Hydro is guided by the following priorities that give consideration to the best interests of all Manitobans, today and in the future:

1. Compliance with legislated rate-setting regulatory framework that sets the maximum general rate increase at the level of inflation or 5%, whichever is lower, to achieve debt-to-equity targets by 2035 and 2040;
2. Stable and predictable rates for customers, together with keeping rates low compared to other jurisdictions (discussed in Section 3.3.2);
3. Gradually improving Manitoba Hydro's financial health over time; and

[6] SM 2022, c 42.
[7] Being Part 4 of *The Crown Corporations Governance and Accountability Act*, *The Manitoba Hydro Act*, and section 2 of *The Public Utilities Board Act*.

4. Ensuring system reliability and modernizing the grid through system investments funded from cash from operations where possible.

3.1.1. Compliance with the Legislation

The Act sets forth changes to the regulatory framework in Manitoba, including the establishment of financial targets and other metrics that will guide rate setting commencing April 1, 2025. While the rate cap and the debt ratio targets in the Act do not strictly apply to this Application, Manitoba Hydro considered the implications of both the pending rate cap and the debt ratio targets for determining the appropriate level of rate increases in the Test Years. It also considered establishing a smoothed rate path and trajectory for customers beyond the Test Years when portions of the Act that relate to how electricity rates are to be established in Manitoba take effect on April 1, 2025.

It is entirely reasonable and appropriate for Manitoba Hydro to plan now for this legal requirement, as it is obligated to do for all other legal, statutory and regulatory requirements that are to become effective at a specified future date. This was discussed by Mr. Fogg:

> *"MR. SVEN HOMBACH: Mr. Fogg, you're aware that some of the Interveners, at least, have argued that in this Hearing, the Board shouldn't be guided by the rate path before that path is actually in effect?*
>
> *MR. ALASTAIR FOGG: Yes, I'm certainly aware of that. And I think while Manitoba Hydro has acknowledged that that -- it's not operative yet, those aspects of Bill 30 -- what were Bill 36 are not a part of the Act are not operative.* ***We've had to be mindful of the path we have to take once it becomes operative and putting -- being in a position to meet those requirements that are in legislation, so there's a balancing of that consideration****."* [8] [**emphasis added**]

[8] Transcript May 29, 2023, pages 2080-2081.

A similar position was also taken by Mr. Bowman:

> *"The current application has not been framed specifically to respond to Bill 36, but the interests of ratepayers for long-term rate stability and predictability suggests the coming effects of Bill 36 should not be completely ignored."*[9]

> *"If -- and -- and -- and tr -- true of anything else, it's passed, it's a law, a future government could change it, sure. The Minister might issue some Directives under it, sure, but I - I don't know that we ever design our -- our --* ***I don't think anybody would design a credible financial forecast that did not build in the law of the land as they understand it will apply at the time they're making the financial forecast for****."*[10] [**emphasis added**]

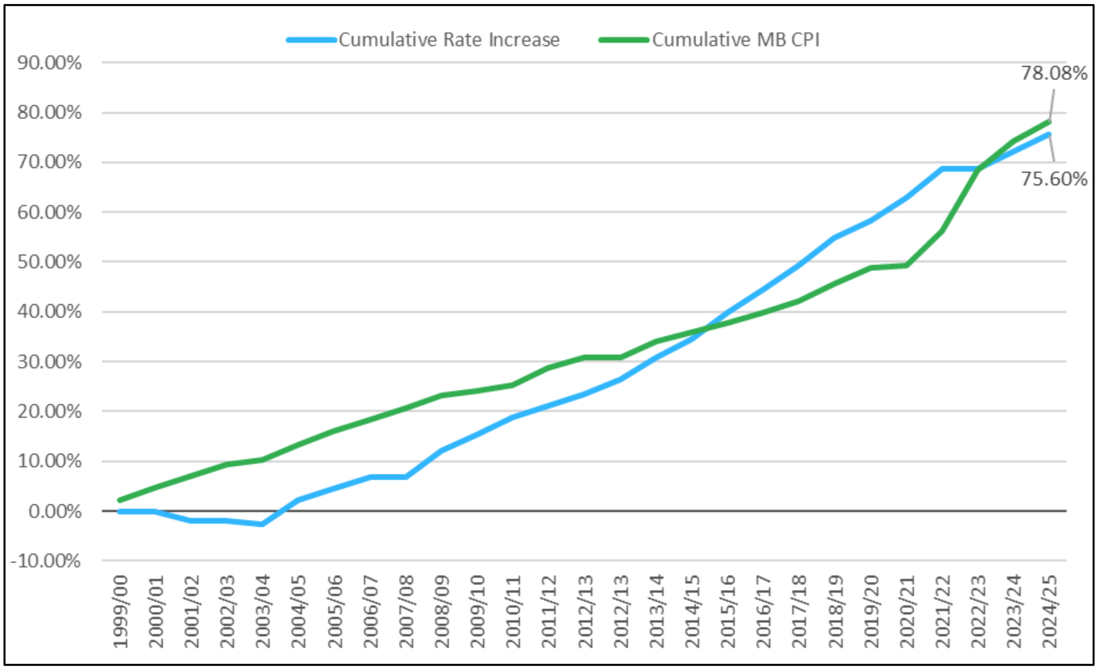
3.1.2. Stable and Predictable Rates

As outlined in Manitoba Hydro's Application and discussed in direct evidence, stable and predictable rate growth for customers, while keeping rates low compared to other jurisdictions, is a priority for Manitoba Hydro and a key consideration in establishing a rate path as part of its financial plans. In its recent Order 9/22, the PUB stressed the importance of considering rate smoothing and reasonable rate trajectories to balance the interests of ratepayers and the financial health of Manitoba Hydro.[11]

The 2% rate path achieves the priority of providing rate stability and predictability for customers along with keeping rates low. From a rate stability perspective, as detailed in MH Undertaking #22, cumulative rate increases are slightly less than cumulative Manitoba CPI since 1999/2000. Cumulative percentage rate increases since 1999/2000 total 75.60% and cumulative Manitoba CPI totals 78.08%. This is shown in the Figure below:

[9] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 5.
[10] Transcript June 9, 2023, page 4065.
[11] PUB Order No. 9/22, page 52.

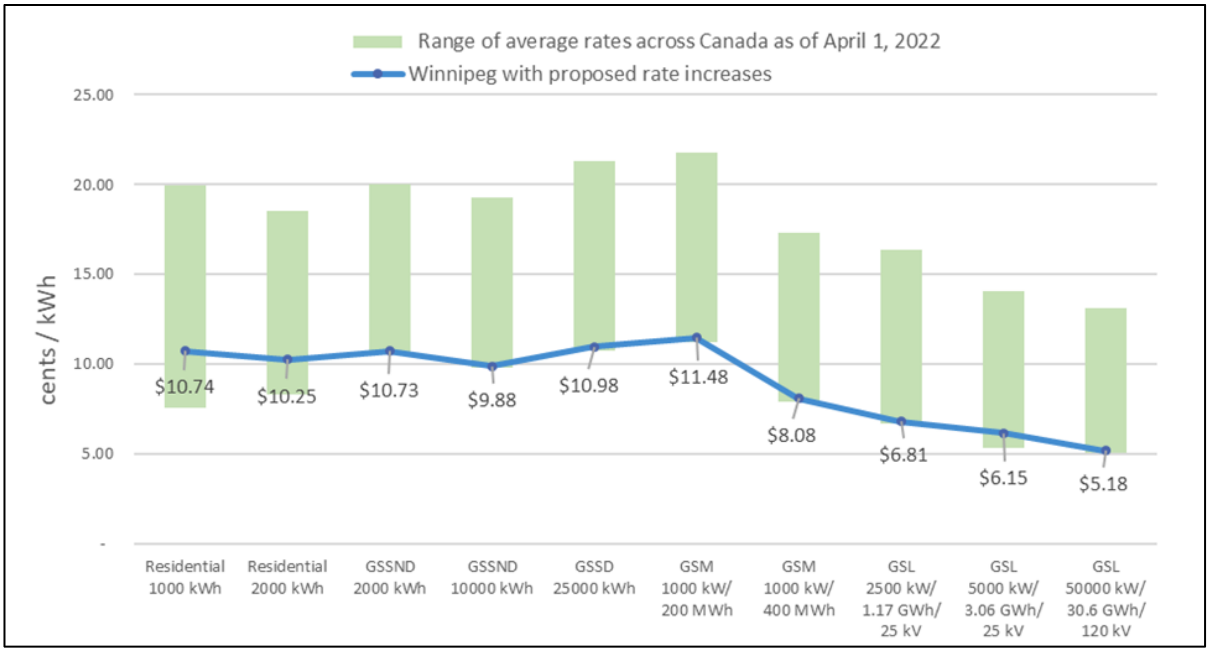
Figure 2



Additionally, as Manitoba Hydro discussed in its direct evidence for the Revenue Requirement Panel, Manitoba Hydro's rates will continue to be the lowest or among the lowest in 2023/24 and 2024/25 even when adjusted to reflect the 2% proposed rate increases while keeping the average rates of all other utilities at those in effect as of April 1, 2022.[12] This is shown in the Figure below:

[12] Transcript May 29, 2023, pages 1978-1979.

Figure 3



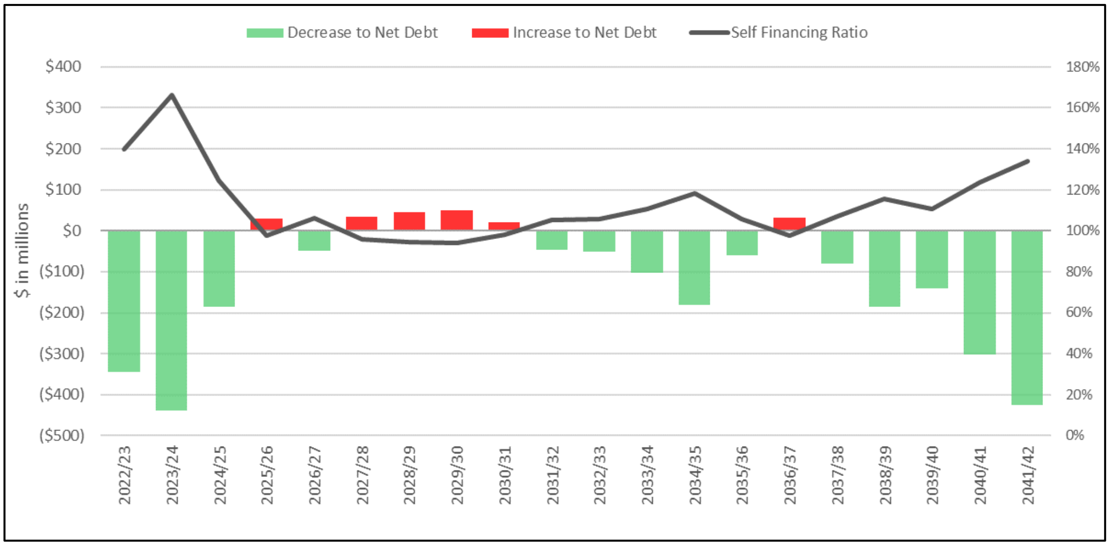
3.1.3. Gradual Improvement Financial Health

Manitoba Hydro's proposed 2% rate path provides steady progress to the achievement of the debt ratio targets outlined in the Act and balances the pace at which Manitoba Hydro pursues its financial targets against the impact to both current and future customers. In order to hit the debt ratio targets, Manitoba Hydro will need to increase its equity (i.e. retained earnings) and decrease its levels of absolute net debt over the forecast period. To achieve this necessary increase to retained earnings and reduction in net debt, the level of net income and cash generated from operations will need to increase. Under the proposed 2% rate path debt growth is minimized between 2025/26 to 2032/33 and subsequently modest reduction in the level of net debt starts in 2033/34. This was highlighted by Mr. Epp in Manitoba Hydro's direct evidence for the revenue requirement panel as follows: "It isn't until midway through the second decade is Manitoba Hydro projected to make noticeable reductions to the net debt balance. The sum of the green bars from 2031 to -- 2031/'32 to 2041/'42, ten (10) years worth of net debt decreases, total 1.5 billion. That is the equivalent to what net debt increased in 2014/'15 and 2015/'16 alone."[13]

[13] Transcript May 29, 2023, page 1982.

This is also depicted in the figure below:

Figure 4



3.1.4. Ensuring System Reliability and Modernizing the Grid Through System Investments Funded Using Cash from Operations

In addition to balancing the pace at which Manitoba Hydro pursues its financial targets against the impact to both current and future customers, the proposed 2% rate path seeks to provide sufficient funds to allow for necessary investments in Manitoba Hydro's existing assets to sustain its systems and address any new requirements.

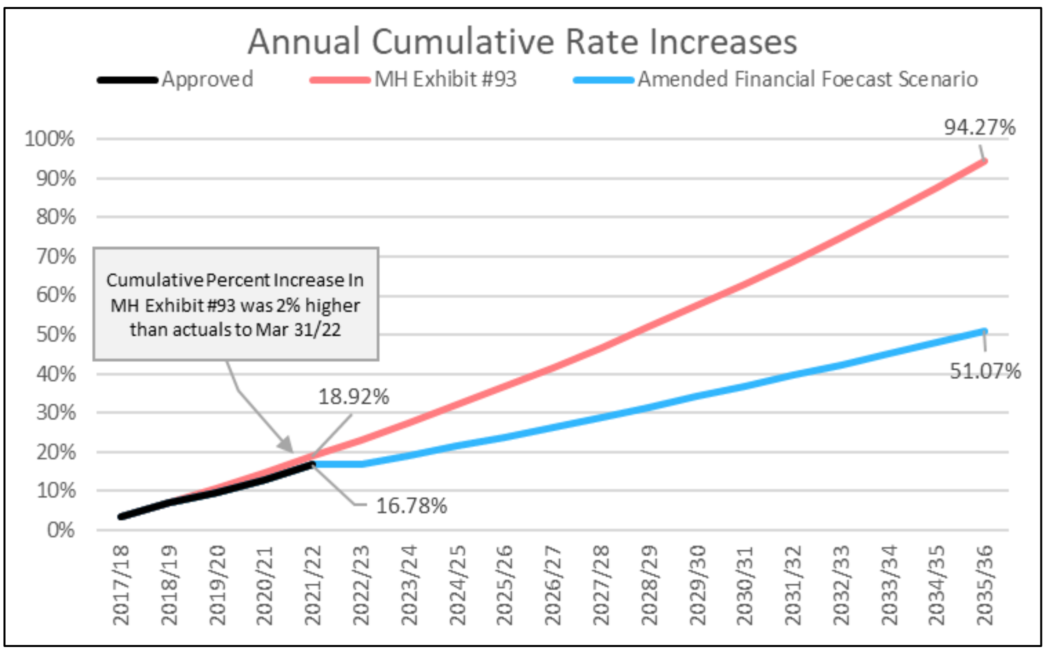
Manitoba Hydro seeks to invest in sustaining existing assets using cash from operations (or internally generated funds) where possible, as this is a key criterion for an entity to be considered self-supporting by credit rating agencies. The proposed 2% rate path will ensure that investments in existing and new assets to sustain and modernize the grid can be made and that those investments are primarily made using cash from operations.

3.2. The Proposed 2% Rate Path Achieves a 75:25 Debt Ratio in the Same Year as MH Exhibit #93

Notwithstanding the debt ratio targets as prescribed in the Act, the previous, long-standing 75:25 debt-to-capitalization target is achieved in 2035/36 under both the current Financial Forecast Scenario and under the MH Exhibit #93 financial forecast as presented in the 2017/18 GRA. MH Exhibit #93 was a scenario that was based on MH16 Update that was requested by MIPUG, and as noted in Order 59/18, was considered by the PUB in determining the approved rate increases in the 2017/18 & 2018/19 GRA.

Achievement of the 75:25 debt ratio in the same year under both forecasts confirms that even if the provisions in the Act are not considered, the 2% rate path provides a reasonable and stable long-term rate path for Manitobans. Notably, however, the cumulative rate increases under the 2% rate path included in the current Financial Forecast Scenario are significantly less than those forecasted in MH Exhibit #93. This is shown in the figure below:

Figure 5



3.3. Value of Long-Term Financial Forecast

Manitoba Hydro's Financial Forecast Scenario is not unlike any other long-term financial projections. It provides directional financial information over the planning horizon based on planning information that is available at the time the forecast is developed.

The proposed 2% rate path is representative of current assumptions and information and therefore does not necessarily represent the rates that will be required in the future to achieve the debt ratio targets. As part of the forecast assumptions, Manitoba Hydro included costs for potential projects that are considered likely to proceed but are not yet approved (i.e. still in the business case phase). That included costs related to the potential SAP S/4 project and the Advanced Metering Infrastructure ("AMI") project. Manitoba Hydro viewed it as appropriate and prudent to include these potential costs in the forecast in order to provide a more accurate view of potential expenses in future years. Mr. Tess and Mr. Fogg discussed this during cross-examination by counsel for the GSS/GSM intervenor:

> *"MR. THOMAS REIMER: And so -- and so, I'm going to suggest this to you and I'm just going to invite you to respond. And I think this is my last question. But it seems to me as though you have brought a very large potential project to the Board that has quite a tight deadline, that has very limited information for the Board to consider, it's asking for a lot of money in the test years, and you're asking the Board to make a decision now, in that environment. And so, my question to you is: Do you feel that you have given the Board sufficient information about this that can permit it to make a decision about your request for SAP S/4HANA costs at this moment?*
>
> *MR. AUREL TESS: Well, I think, first of all, we've given you the best information we have, given the timing of the rate application. And we've been completely transparent with everyone, I believe, in terms of where we are at in the business case process. We've also committed to coming back and -- and reporting on this. I think Mr. Fogg referenced the deferral that is also included in the SAP costs, which essentially, reduces the revenue requirement for the test years; not completely, but reduces it. Because I believe it's amortized over ten (10) years, subject to check. So -- so the impact on -- on the test years is not as material as the 156 million. So I guess, framing it as what we're asking for I would kind of look at it as the impact on the -- on the revenue requirement is -- and I mean, the other project that you haven't mentioned, but I -- you know, Mr. Williams mentioned, is AMI. And I think the same goes for that project. It's material. We take it very seriously. You know, we're going to do everything we can to keep everyone informed as we go along.*

MR. ALISTAIR FOGG: I think, Mr Reimer, just to add, we -- we viewed it as more appropriate to include those items and -- and show that to the Board so that they're aware those are upcoming versus coming later after a business case decision may have already been made. We wanted to include those in the forecast now.

MR. AUREL TESS: We saw it as appropriate to start the conversation given where we're at in the -- in the process. But I -- I think you might be asking us why we didn't include those numbers in the forecast if we hadn't included them."[14]

As noted in Manitoba Hydro's Application, the energy sector has been seeing unprecedented levels of change in recent years due to the trends of decarbonization, digitization and decentralization. The pace and breadth of these changes are unpredictable, and the result is increasing long-term forecasting uncertainty. Future changes in key planning assumptions could impact future rates compared to the current forecast rate path. This reality was most recently exemplified by the change to the forecast rate path that was necessary from the reduction in the provincial debt guarantee and water rental fee charged by the Province of Manitoba. The assessment of how changes in key planning assumptions may modify the forecast rate path would be dependent on the nature of the changes, whether they are enduring or one-time changes, and Manitoba Hydro expects these would be the subject of future General Rate Applications.

While this uncertainty exists, the degree of uncertainty is much lower in the early years of the financial forecast compared to the final years of the forecast. This concept was addressed by Mr. Fogg:

"DR. BYRON WILLIAMS: And, Mr. Fogg, with reference to the term 'primarily beyond the test years', Manitoba Hydro has a fair degree of confidence in the load scenario as it relates to '23/'24 and '24/'25, fair, or Mr. Epp, whoever?

[14] Transcript May 30, 2023, pages 2479-2481.

MR. ALASTAIR FOGG: I would agree with that statement.

DR. BYRON WILLIAMS: You have significantly less confidence beyond the test years, agreed?

MR. ALASTAIR FOGG: I -- I would suggest that -- that in any aspect of a forecast, as you move out in time, the certainty of that forecast lessens, you know, twenty (20) years from today versus two (2) years from today. That includes that load forecast that we're discussing right now." [15]

As detailed in the next section, there are a number of factors in the near term that are more certain that are driving the need for rate increases in the Test Years.

3.4. Changes to Export Contracts and Interest Rates Support Rate Increases in the Test Years

While there is uncertainty associated with the evolving energy landscape, there are near term changes that Manitoba Hydro expects will impact its revenue requirement and support the proposed rate path. Both the expiration of dependable export sales agreements and the refinancing of debt at higher interest rates are expected in the coming years and will impact Manitoba Hydro's revenues and costs. Mr. Tess spoke to this in his opening remarks for the revenue requirement panel:

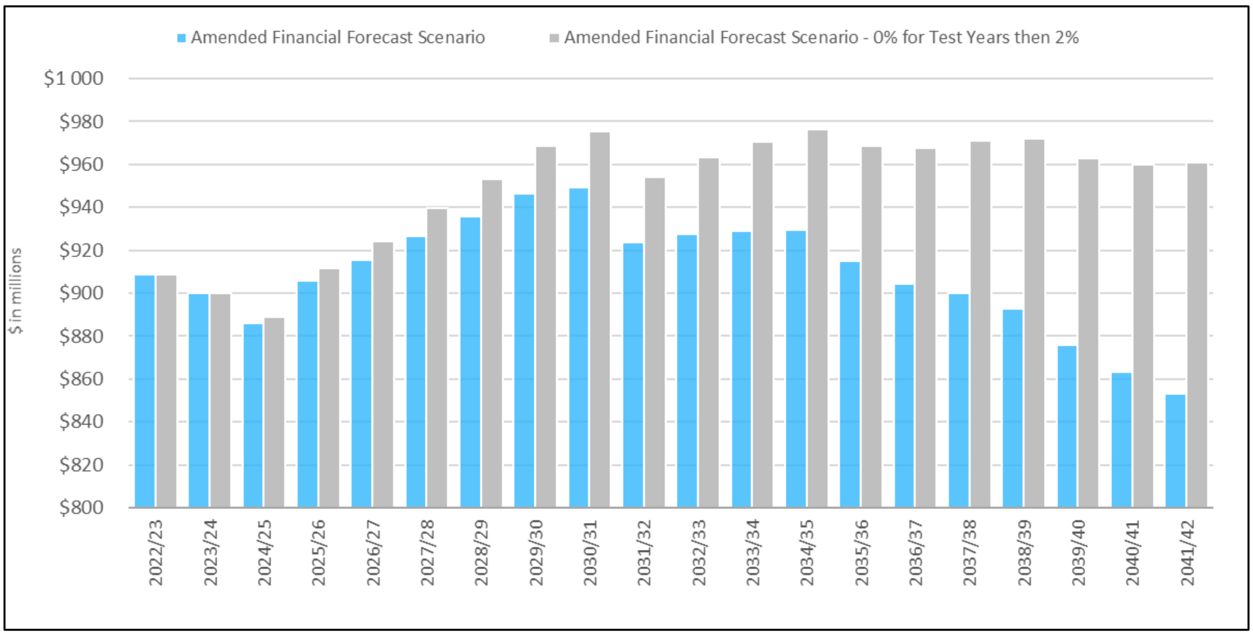
"The trends of decarbonization, digitalization, and decentralization will continue to shape and disrupt Hydro's business environment in the coming years. The pace and breadth of these changes are unpredictable but the 10 billion of long-term debt, which Manitoba Hydro has maturing this decade is not. We know when it's maturing. With no external borrowing for new major capital on the horizon this decade, now is the time for recovery of Manitoba Hydro's financial health and financial metrics to proactively position ourselves as financially resilient to respond to the emerging needs and expectations of our customers."[16]

[15] Transcript May 30, 2023, page 2297.

[16] Transcript May 29, 2023, page 2017.

The proposed rate increases in the Test Years are a key component in allowing for the debt retirement and minimization of new debt required to reduce cumulative finance expense over the forecast period. The figure below compares finance expense assuming the 3.6% interim rate increase is confirmed and the proposed 2% rate increases in 2023/24 and 2024/25 are approved versus no increases in 2023/24 and 2024/25 (but assuming the 3.6% is still confirmed). Without the proposed increases in 2023/24 and 2024/25, finance expense continues to grow, resulting in an additional, cumulative $800 million in finance expense over the forecast period:

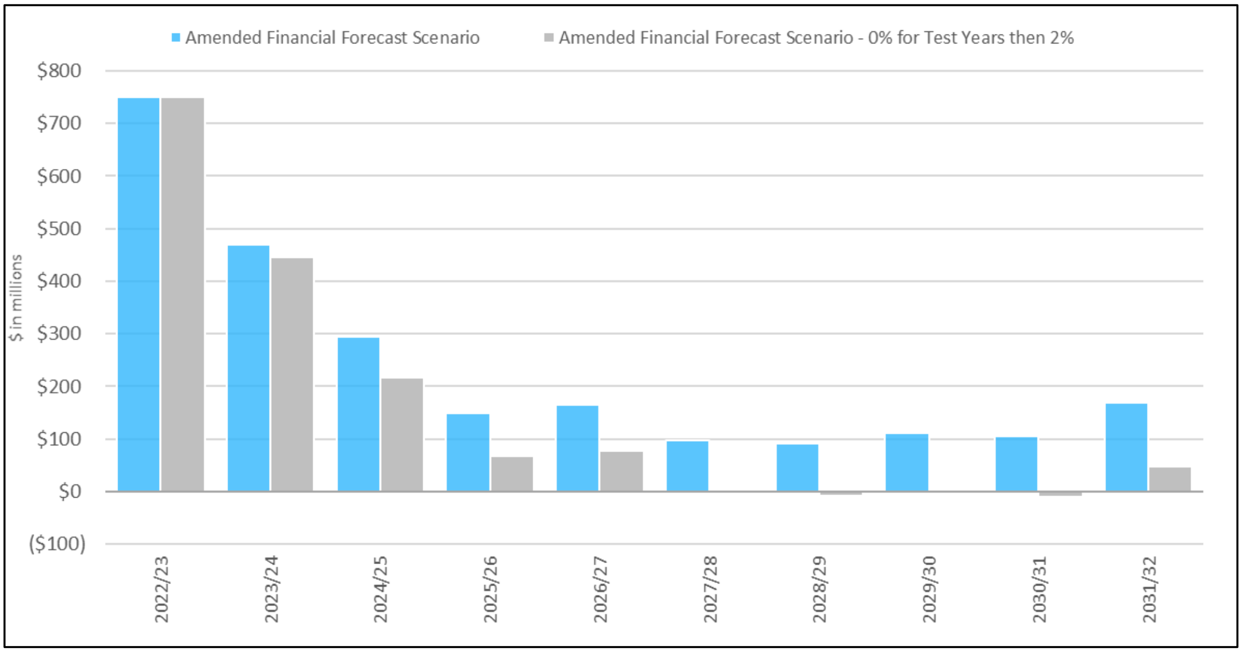
Figure 6[17] - Finance Expense



Similarly, confirmation of the 3.6% interim rate increase and the proposed 2% increases in the Test Years also help address the anticipated reduction in revenue associated with the expiry the Northern States Power ("NSP") system power sale in 2025/26 and subsequent expiry of other dependable export contracts. The following graph shows if the 3.6% interim rate increase is confirmed but the proposed rate increases in 2023/24 & 2024/25 are not approved, Manitoba Hydro would be forecasting losses from 2025/26 to 2030/31, even if 2% rate increases are awarded from 2025/26 to 2030/31.

[17] MH-42, MH Revenue Requirement Presentation, May 29, 2023, page 22.

Figure 7 - Net Income/Loss



During the oral hearing, Mr. Epp spoke to the importance of the 3.6% interim rate increase and the 2% rate increases in the Test Years to support net income in the first years of the financial forecast:

> *"Mr. Hombach, I'm going to use the word "only" again, only 49, 41, 55, and 46 million. When you look at the impact in a year for some of those risks above that pales in comparison to what they are. So, let's take 49 million of net income in 2028 and let's -- let's pick a below-average water flow year, not the drought, in the same year. Okay? That's minus -- almost minus a hundred -- a hundred million. And that runs -- that runs things very fine. Okay? You're running a very fine line with net income, under average conditions and average weather, to be running things at $50 million, when you look at the size of those risks that we're facing.* ***The 3.6 and the 2 percents are providing a little bit of protection for these risks, should they -- should one happen or should partially happen or some off-set the other. So, when we see net income, that is, $40 million a year, it doesn't put us in a very warm and fuzzy position****."* [18] [**emphasis added**]

[18] Transcript May 29, 2023, page 2114.

Notably, Mr. Bowman also identified the end of the NSP system sales agreement and the refinancing of debt as reasons why he supported the proposed 2% rate increases in the Test Years:

> *"Well, the -- the recommendation on -- on 2 percent was based on -- on the two (2) things I highlighted, the -- the first slide, which is Bill 36, which limits the ability to respond with rate response in the future, and the financial projections which show that there are some things that are going to, I'll say, move against us in the next few years, the -- the ending of the NSP contract and refinancing debt, for example. When you look at those two (2) in combination and you say, you know, we can't hold our powder dry and only respond to interest rates when they arise, then we should -- then we have to respond today because, in all likelihood, I think that that would probably be refinanced at a rate higher than people were getting, you know, in the past."*[19]

3.5. Higher Rate Increases in the Test Years

In addition to questions on the requested rate increases in the Test Years and the 2% rate path, Manitoba Hydro also received questions from the PUB through the information request process and as part of the oral hearing on the potential impact of higher than requested rate increases in the Test Years. One of the scenarios examined was the possibility of 3.5% rate increases in 2023/24 and 2024/25.[20] Under this scenario, rates after 2023/24 and 2024/25 would be 1.55% for the remainder of the 20-year forecast to achieve the 70% debt-to-capitalization target in 2039/40. This scenario also results in $0.6 billion less revenue collected from customers over the 20-year forecast period and may provide room (or the potential opportunity) for higher rate increases in specific future years should any risks arise that would impact achievement of the debt ratio targets in the Act, assuming a long-term forecast level of inflation of 2% setting the rate cap. Additionally, an approach of higher rate increases in the Test Years with lower increases thereafter would mitigate the risk associated with forecast inflation being less than 2% in future years. Mr. Fogg explained Manitoba Hydro's perspective as follows:

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[19] Transcript June 9, 2023, page 4017.
[20] PUB/MH II-9a-d.

"MR. SVEN HOMBACH: […] One (1) of the questions the -- the Board advisors had asked Manitoba Hydro in Information Request is: What would happen if the rates for '23/'24 and '24/'25 were still at 3.5 percent as under the initial Application? And, Mr. Fogg, I -- I take it you're familiar with this response?

MR. ALASTAIR FOGG: Yes, I'm familiar with the response.

MR. SVEN HOMBACH: So -- so if that were the case, Manitoba Hydro assumes that it would only need 1.55 percent going forward?

MR. ALASTAIR FOGG: The resulting effect is then 1.55 percent annual rate increases thereafter to meet the 70 percent debt-ratio target.

MR. SVEN HOMBACH: So from the Utility's perspective, under a scenario like that, would that give you additional breathing room to deal with things like a seven (7) year drought that has a half percent rate impact?

MR. ALASTAIR FOGG: Such a scenario would -- would provide some of that additional – I guess, to -- to use your term -- breathing room or -- or rate increase opportunity. And, you know, this scenario is viable from the perspective of meeting the provisions of the Act, and we had to balance that consideration against what -- what our view was from a stable and predictable rate path perspective when we sought the - the 2 percent rate path."[21]

3.6. Confirmation of the 3.6% Interim Rate Increase is Essential to Manitoba Hydro's Financial Health

As explained in Tab 3 (Amended) of the Application, confirmation of the 3.6% interim rate is required to help address Manitoba Hydro's increased revenue requirement, improve Manitoba Hydro's financial health, and provide rate stability for customers in the long term.

[21] Transcript May 29, 2023, pages 2075-2076.

Manitoba Hydro acknowledges that the purpose of interim rates is to relieve the applicant from the deleterious effects caused by the length of the proceedings, and that while rates must be just and reasonable whether approved by interim or final order, interim rates must be just and reasonable on the basis of the evidence filed at the final hearing.

Based on the full and extensive record of this hearing, Manitoba Hydro submits that confirmation of the 3.6% interim is just and reasonable in the circumstances and that it should be finalized. Manitoba Hydro emphasizes that none of the Interveners nor Intervener experts recommended reducing or changing the 3.6% interim rate. All were supportive of confirming the 3.6% interim rate as Manitoba Hydro has requested.

Confirmation of the 3.6% interim rate increase is a key part of Manitoba Hydro's proposed rate path and is essential to Manitoba Hydro's financial health. The 3.6% interim rate increase has a significant favourable impact on Manitoba Hydro's long-term financial results, and the ability to offer stable, predictable rates to customers while meeting the mandate to provide safe and reliable service.

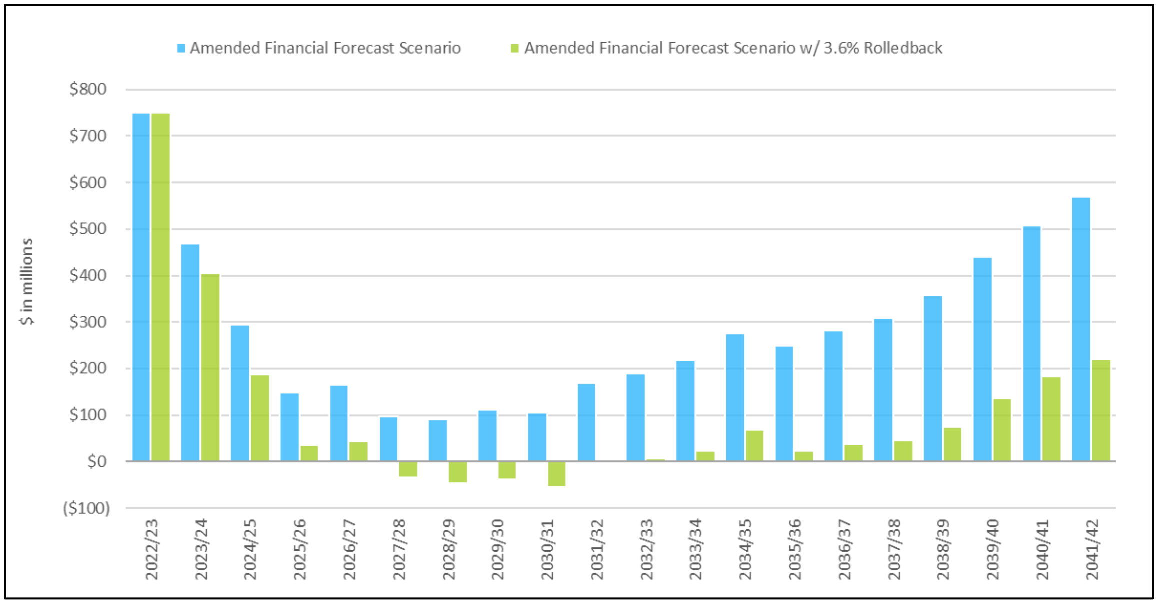
In contrast to years where there is higher net export revenue due to temporary water conditions and market prices, confirmation of the 3.6% interim rate contributes to Manitoba Hydro's domestic revenue in each year of the forecast and as such its impact is enduring. This was explained by Mr. Epp:

> *"MR. GREG EPP: Mr. Hombach, if I can add to that. Like a -- a very high water year and very advantageous export prices is great and it's really good news, but it -- it's not enduring like a rate increase would be. So, despite the windfall of water, having the volume and -- and sole -- not only have the volume, but having high prices is great but we already see that there's a softening in the export price market, whereas a -- a 3.6 percent rate increase is part of the long game and it's enduring and it -- and it adds to the revenues every year. So, they are somewhat different in terms of their impact to the bottom and -- line and how they stabilize a financial situation."*[22]

[22] Transcript May 29, 2023, pages 2097-2098.

If the 3.6% interim rate increase were rolled back to 0% on September 1, 2023 and no rate increase was granted in the 2023/24 fiscal year, but the 2% proposed increase was awarded in 2024/25, Manitoba Hydro would experience an additional $1.2 billion in finance expense and a $3.7 billion reduction in retained earnings over the 20-year forecast period as compared to the financial forecast presented by Manitoba Hydro. Manitoba Hydro would also be projecting losses in 5 years (2027/28 to 2031/32) of the 20-year forecast scenario under this scenario. The difference in annual net income is reflected in the figure below:

Figure 8: Net Income/Loss[23]



Mr. Tess also addressed the potential of the 3.6% interim rate increase being reduced and the impact to achieving a 70:30 debt-to-capitalization ratio by 2039/40:

> *"MR. SVEN HOMBACH: So -- so, with -- from your perspective, with a 2 percent rate path, is there any room to reduce the 3.6 percent interim rate increase why -- while still meeting 70/30 by 2040?*
>
> *MR. AUREL TESS: I think any reduction in the early years of the forecast, that would be detrimental, I think, to the Debt Repayment Plan that we presented. Is there's any room? There's always tradeoffs and the tradeoffs*

[23] MH-1, Application Tab 3 (Amended), page 26.

would be not having sufficient cash to -- to meet our targets potentially, higher interest costs, and potentially reduction in service levels. So, we -- that -- that's something -- again, we took all of this into account in the proposed rate path, so -- especially early – early rate increases have that compounding effect in the early years."[24]

3.6.1. If the Granting of the Interim Rate Relief was not Just and Reasonable at the Time, the Least Preferred Option is a Retroactive Refund or Rollback

Manitoba Hydro accepts that the PUB has the jurisdiction to set, review, and confirm or change interim rates and it may compensate for, or refund, any excess amounts collected.[25] The PUB's exercise of its jurisdiction is discretionary, and subject to judgement and decision-making in accordance with sound utility practice.

While interim rates may be reviewed in a retrospective manner,[26] the PUB should still give consideration to, and favour, prospective ratemaking when warranted and practical to do so. Manitoba Hydro submits that the PUB should seriously consider the negative impact of any retroactive refund or rollback on the Manitoba Hydro's amended Financial Forecast Scenario that underpins this Application as described above.

During the hearing, Vice-Chair Kapitany asked whether there were mechanisms Manitoba Hydro could use to refund revenue collected through the interim rate increase. Mr. Epp opined that two options may be a bill credit or a rate rider for a certain amount of time.[27] While these options are possible, they are administratively complex and would take considerable time and effort to implement and could also be difficult for customers to understand, particularly when the bill credit or rider expires and customers' bills increase.

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[24] Transcript May 29, 2023, pages 2117-2118.

[25] *The Crown Corporations Governance and Accountability Act*, C.C.S.M. c. C336 (the "CCGAA"), section 27. While Manitoba Hydro is no longer referenced in Part 4 of the CCGAA, the explanatory note in the Act is clear that Section 4 of the CCGAA currently applies to the regulation of electricity rates until March 31, 2025.

[26] *Bell Canada v. Canadian Radio-Television & Telecommunications Commission,* 1989 CarswellNat 697, [1989] 1 S.C.R. 1722 (SCC), paragraph 44.

[27] Transcript May 31, 2023, pages 2565-2566.

Manitoba Hydro concurs with the pragmatic opinion offered by Mr. Bowman regarding the importance of looking forward when considering the potential retroactive adjustment to any interim rate, if warranted:

> *"I think this goes to that image of a sort of stirring [sic steering] the super tanker. We -- we made the turn. We may have turned a little farther than we should have, it'll correct. Rather than sending people cheques or doing something like that, you know, we'll -- we'll allow that correction to flow through in the way that we project Hydro's revenues going forward and the way that we do rate increases going forward."*[28]

3.7. Forward Looking Rate-Setting

In Mr. Rainkie's evidence, he presents three analytical perspectives or alternatives to Manitoba Hydro's proposed 2% rate path. His analytical perspective #3 suggests longer-term intergenerational equity over 30 years with a mid-term rate pause for current customers. Scenario #3 is underpinned by Mr. Rainkie's conclusion that ratepayers over the last 12 years were essentially overpaying before major capital projects were in-service, and that a remedy would be a rate-pause in the test years as a way to correct this alleged overpayment. [29]

While Mr. Rainkie agreed in cross-examination that "setting rates is forward looking based on the financial outlook,"[30] his analytical perspective #3 is clearly contrary to the rule against retroactive ratemaking. The PUB has the authority to set rates on a prospective basis only and has no authority to allow recovery on a retroactive basis. Rates are raised or lowered to reflect current conditions. Regulators cannot design a future rate so as to enable the utility to recover a past loss or to rectify for customers some past over-compensation of the utility. The rule against retroactive ratemaking is well-established. As the Supreme Court of Canada stated:

[28] Transcript June 9, 2023, pages 4014-4015.
[29] CC-7, Revenue Requirement Evidence Prepared by Darren Rainkie, April 3, 2023, section 9.5; Transcript June 1, 2023, page 2667.
[30] Transcript June 1, 2023, page 2751.

> *"... The Board was seeking to rectify what it perceived as a historic overcompensation to the utility by ratepayers. There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation. It is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates…"*[31]

Mr. Rainkie's analytical perspective #3 amounts to retroactive ratemaking and should not be considered or accepted by the PUB.

4. ENTERPRISE RISK MANAGEMENT & UNCERTAINTY ANALYSIS

4.1. Manitoba Hydro is in the Process of Establishing a Formal Enterprise Risk Management Program and is not the Historical Siloed View of Risk Management

Manitoba Hydro is in the process of further developing and establishing its formal Enterprise Risk Management ("ERM") program to provide:

- an enterprise-wide view of the risks faced by the organization;
- a proactive, comprehensive, and standardized approach to the strategic management of these risks; and
- facilitation of a risk infirmed cultured across the enterprise where each individual group not only knows and manages their individual risks but considers risk holistically across the enterprise, and with a common risk language and tools, considers risk throughout its decision-making processes.[32]

Manitoba Hydro's ERM Framework[33] outlines the approach to risk management, governance structure, roles and responsibilities and methodology that Manitoba Hydro will use to manage risks. This framework is based upon industry standard best practices and incorporates aspects of both the COSO Enterprise Risk Management framework model and ISO 31000 Risk Management model.

Previous efforts of the risk management function at Manitoba Hydro were focused more

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[31] *ATCO Gas And Pipelines Ltd v Alberta (Energy And Utilities Board)*, 2006 SCC 4, paragraph 71.
[32] MH-1, Application Tab 2, Section 2.7.3.
[33] MH-1, Application Tab 2, Section 2.7.5.

on a historical, siloed risk management approach than enterprise risk management (RM vs. ERM). Manitoba Hydro experienced the challenges and limitations of this siloed approach (as listed on page 47 of rebuttal evidence) and this baseline formed the foundation and basis for Manitoba Hydro's maturity assessment of its ERM Program.

4.2. It is Undisputable that Manitoba Hydro Currently Faces Increased Levels of Enterprise Risk and Uncertainty

Manitoba Hydro is facing increasing levels of enterprise risk and uncertainty. Manitoba Hydro expects its risk universe (i.e. the amount of risks that can affect the organization, on every level) to continue to evolve and grow over the next decade, with the increased likelihood of this universe increasing vs. decreasing.[34]

Manitoba Hydro defines risk as "the uncertainty of outcome, whether positive opportunity or negative threat, of actions or events."[35] Building off that definition, the overall uncertainty embedded in both the evolving energy landscape and government considerations regarding climate change and emission targets will be a significant driver of this projected, increasing risk universe. Further, Manitoba Hydro expects this projected growth in its risk universe to include both potential negative threats (i.e. downside risk) and potential positive opportunities (i.e. upside risk). These risks are largely driven by the uncertainty in the evolving energy landscape and federal/provincial considerations to both climate change and emission targets. The pace and breadth of these anticipated changes remain highly unpredictable and uncertain for Manitoba Hydro and its future.

Mr. Rainkie asserts that Manitoba Hydro has framed a one-sided picture of risks that is overly negative.[36] However, Mr. Rainkie fails to consider that the definition of risk is the uncertainty of outcome and that uncertainty could be either an opportunity or threat. In contrast to Mr. Rainkie's assessment of Manitoba Hydro's risk, Mr. Colaiacovo on behalf of the Consumers Coalition, provided evidence that the global energy transition is presenting increasing uncertainty, not clarity, for Manitoba Hydro.[37] Mr. Colaiacovo provided many examples of this transition such as "technology announcements almost

[34] AMC/MH II-1a-c.
[35] MH-1, Application Tab 2, Section 2.7.2.
[36] CC-7, Revenue Requirement Evidence Prepared by Darren Rainkie, April 3, 2023, pages 29-30.
[37] CC-23, Pelino Colaiacovo, Morrison Park Advisors Presentation, June 6, 2023, slide 5.

daily" and "profound impact on energy markets and loads, with no stability in sight."[38] Manitoba Hydro agrees with Mr. Colaiacovo's assertions in this specific regard.

4.3. Manitoba Hydro's Risk Assessments are Complete and Balanced for Rate Setting Purposes

Manitoba Hydro disagrees with Mr. Rainkie's assertion that Manitoba Hydro's risk assessments are incomplete and imbalanced.[39] As mentioned in response to AMC/MH II-1c and as already noted in section 4.2 above, it is important to reference and understand the definition of risk - "risk is the uncertainty of outcome, whether positive opportunity or negative threat, of actions or events."

Mr. Rainkie was asked to provide comments on the risks contained in the table in the response to Coalition/MH I-1b and indicate if they were increasing, decreasing or remaining steady. Mr. Rainkie responded that it was impossible for him to respond to the question but did offer comments on some specific risks in the table and others.[40] Manitoba Hydro submits that many of Mr. Rainkie's comments and assessments are incorrect and leading to inaccurate conclusions. A common misunderstanding throughout Mr. Rainkie's resulting assessments (based on the definition of risk above) is the failure to recognize that uncertainty is an element of increased risk.

Below are Manitoba Hydro's response to some of Mr. Rainkie's specific assertions. Further discussions on both aging asset risk and interest rate risk are found in section 10.1 and 16.2, respectively.

<u>Drought Risk</u>

While Mr. Rainkie asserts that Manitoba Hydro's drought risk is not increasing, it is Manitoba Hydro's position that the importance of understanding the risks and uncertainty surrounding drought are increasing.

The magnitude of financial impacts to Manitoba Hydro from a drought event are a product of several factors including:

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[38] Transcript June 6, 2023, page 3293.
[39] CC-7, Revenue Requirement Evidence Prepared by Darren Rainkie, April 3, 2023, pages 29-30.
[40] PUB/Coalition I-28.

- the volume of energy required to cover Manitoba Hydro's hydroelectric generation deficit;
- fuel costs for thermal generation used to offset reduced hydropower production;
- purchase price of energy imports required from the MISO market during these events; and
- the borrowing costs associated with borrowing requirements to offset reduced revenues and drought costs.

Recent experience from managing the 2021 drought event demonstrated the high amount of volatility in fuel costs, energy prices, and borrowing costs. The volatility of gas and power prices was highlighted in Appendix 4.2 of the Application.[41]

From a hydrological perspective, there is low confidence in projections of how extreme events such as drought may change for the Manitoba Hydro system.[42] However, many projections anticipate the intensity and frequency of extremes to increase in the future, and Manitoba Hydro recognizes the importance of reviewing and updating the underlying hydrologic records used to estimate drought risk. As described in the Application, Manitoba Hydro is currently undertaking a multi-year Corporate Flow Record Improvement initiative to review hydrologic drought risk and evaluate impacts of record improvements to drought risk estimates, among other items.[43]

Cyber Security Risk

Manitoba Hydro disagrees with Mr. Rainkie's assertion that there could be opportunities for reduced cyber security threats as a result of the evolving energy landscape areas concerning decarbonization, decentralization and digitalization. Mr. Rainkie has not advanced any evidence on the record that would support such an assertion and Manitoba Hydro relies on its earlier evidence that recent geopolitical uncertainty has increased the overall level and frequency of cyber-related events throughout the world.

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[41] MH-1, Application Tab 4, Appendix 4.2, Section 3, page 5.
[42] MH-1, Application Tab 5, page 30; MH-1, Application, Appendix 5.4, Section 4, pages 24-25.
[43] MH-1, Application Tab 5, pages 30-31.

4.4. The Temporary Pause in Manitoba Hydro's Uncertainty Analysis is Prudent and Justified, and will be Reintroduced in Future Regulatory Proceedings

As Manitoba Hydro outlined in its rebuttal evidence, the absence of the uncertainty analysis in this Application was not a step backward but rather a prudent pause while prerequisite initiatives are further developed before the inputs, assumptions and methodologies underpinning the uncertainty analysis are revisited with more fully developed information.[44] This was discussed further by Mr. Epp during cross examination:

> *"MR. SVEN HOMBACH: Is it the Utility's intention to start a full uncertainty analysis again once an energy policy has been released?*
>
> *MR. GREGORY EPP: I think the energy policy is just one of, like, a key document that would impact the way we look at uncertainty and risk going forward. You know, billing out our Enterprise Risk Management Program, how the uncertainty analysis will fit in with that, and looking at risks across the entire enterprise, and the findings that are coming out of the IRP, right? There's's -- there's a number of things that the group that is working hard on the IRP is investigating things that will change as the energy landscape changes. These are things that -- that, you know, we're just tyring to put our thumb on and our pulse on. And we have to do some more understanding and -- and research on how that should be modelled and how that should be folded into any financial forecast. At the same time, there's -- there's things that are changing in --in some of the risks that we currently know today. I'll say, like, our export price forecast. How is the changing energy landscape and some of the things that -- that Daymark brought forward -- how those resources are changing the -- the resource mix in that area are going to impact the price and the signals that we get for our surplus energy here. So even -- even if the energy policy should drop on said date or even if the IRP drops this summer, there's still a lot of work to be done to comb through all that information, to understand it, to model it, to test it, and make sure that -- that we have a fairly strong*

[44] MH-24, MH Rebuttal Evidence, May 5, 2023, page 48.

understanding for these things before we release it. Not only review it internally, but bring it into a forum like this." [45]

Manitoba Hydro will complete and file an uncertainty analysis as part of its next GRA. This was confirmed by Mr. Epp during cross examination by MIPUG.[46] The exact form of this future uncertainty analysis is yet to be determined and may differ from the format of the uncertainty analysis that was previously filed.

Manitoba Hydro agrees with Mr. Bowman's evidence[47] that in future GRAs, an uncertainty analysis could be a useful tool for assessing the likelihood of reaching the legislated financial targets under specified conditions, rather than assessing the targets themselves.

5. ELECTRIC LOAD SCENARIO

5.1. Emerging Energy Landscape and Impacts of Electrification Across all Sectors

The changing energy landscape has brought unprecedented uncertainty to the future electrical needs of Manitobans. Energy policy (Federal, Provincial and Municipal) and emerging technologies that aim to reduce Manitoba's carbon footprint have the potential to dramatically change how Manitobans utilize electricity into the future and more importantly, the role Manitoba Hydro will play in helping supply the electricity needed. The emerging energy landscape, primarily by way of decarbonization as described in Tab 2 (pages 6-7) of the Application, has the potential to increase electricity demand due to changing to electricity energy sources for transportation, space heating and industrial processes.

5.2. Integrated Resource Plan (IRP) as a Tool to Understand Potential Futures

In Tab 2 (pages 35-39) of the Application, Manitoba Hydro provided insights on the scenarios and potential future range of load being contemplated as part of the 2023 IRP. The scenarios were developed to facilitate study of uncertainty in the future resulting from various drivers, including policy, in a process that incorporated external engagement

[45] Transcript May 29, 2023, pages 2055-2057.
[46] Transcript May 31, 2023, pages 2525-2526.
[47] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 19.

to ensure that the perspectives of interested parties (including customers and Indigenous peoples) are represented in the planning work.

Figure 9[48] - Range of Energy in 2023 IRP Scenarios (GWh)

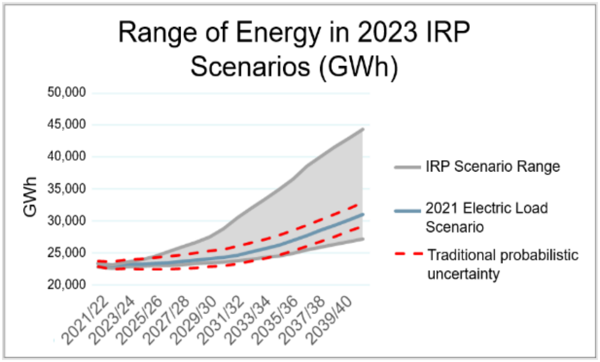
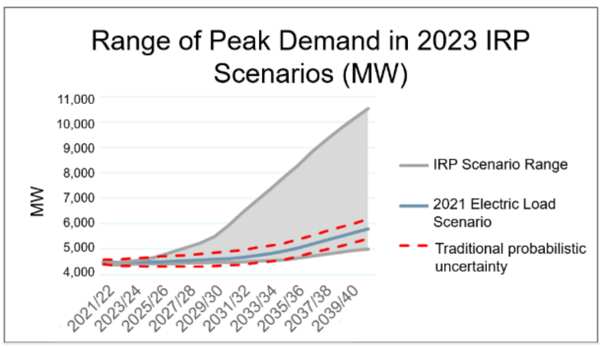


Figure 10[49] - Range of Peak Demand in 2023 IRP Scenarios (MW)



The scenario range provides bookends of potential futures that include various levels of decarbonization strategies, from Scenario 1 which includes limited amounts of decarbonization up to Scenario 4 which includes high levels of decarbonization on a pathway toward net zero. The wide range observed in the figures above, illustrates the significant uncertainty in future load growth, particularly beyond 2030.

5.3. Reliability of the Electric Load Scenario

Manitoba Hydro produced a 20-year electric load scenario for the purpose of this Application to provide directional information for the next 20 years.[50]

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[48] MH-1, Application Tab 2, Figure 2.11, page 38.
[49] MH-1, Application Tab 2, Figure 2.12, page 38.
[50] MH-1, Application Tab 5, Appendix 5.1.

Manitoba Hydro recognizes there is always uncertainty in energy forecasting and in the response to Coalition/MH I-50a, explained that the name change from Manitoba Hydro's traditional nomenclature of "Electric Load Forecast" to "Electric Load Scenario" was to capture the unprecedented uncertainty and pace of change that could impact resource requirements beyond the test years. The 2021 Electric Load Scenario represents Manitoba Hydro's best projection of Manitoba's future energy needs under current assumptions.[51] The 2021 Electric Load Scenario leverages forecasting models consistent with industry best practices and includes key planning assumptions related to emerging technologies (like the electrification of transportation) and behind the meter technology (like solar photovoltaic). Manitoba Hydro's forecast scenario also includes Efficiency Manitoba's energy efficiency plan which projects achieving legislated targets of an average 1.5% of electrical energy reductions.

Manitoba Hydro recognizes that the unprecedented uncertainty may impact the long-term projections and is currently conducting the Integrated Resource Plan to better understand the potential impacts which will be considered in the development of future long-term load and financial forecast. Mr. Epp confirmed that while there is always uncertainty in preparing any long-term forecast, the 2021 Electric Load Scenario presented as part of the Application made use of the best information available to Manitoba Hydro at the time and is reliable and useful for this proceeding.[52]

6. MANITOBA HYDRO'S FORECAST OF EXPORT REVENUES, GENERATION COSTS AND FUTURE SUPPLY/DEMAND BALANCE IS REASONABLE

6.1. Net Export Revenue Forecast Components

Net Export Revenue represents Export Revenue (i.e., Extraprovincial) minus flow- related costs which primarily consist of Water Rentals and Fuel and Power Purchased.[53] Fuel and Power Purchased includes import purchases as well as wind/solar power purchase agreements.[54] In determining Net Export Revenue, the Manitoba load is treated as a must meet obligation. To the extent the Manitoba load is growing, and in the absence of new

[51] CC/MH I-50c; MH-1, Application Tab 5, pages 4-7.
[52] Transcript May 30, 2023, pages 2258-2259.
[53] MH-1, Application Tab 4, Section 4.2.6, page 21. Note that this definition of Net Export Revenue is used in the Financial Forecast Scenario and is somewhat different than the definition used in the PCOSS, which is based on Order No. 164/16 and is the residual export revenue after deducting specified costs allocated.
[54] MH-1, Application Tab 4 (Amended), page 20.

resources, load growth decreases the surplus energy available for export and increases imports. This causes a gradual reduction in the Net Export Revenue over time, all other factors being held equal.

6.2. Daymark Finds Export Revenue Forecast Reasonable

In response to Intervenor submissions that a review of export information is critical to an evaluation of the influence the export market has on Manitoba Hydro's financial forecast,[55] the PUB retained the services of an independent expert, Daymark Energy Advisors ("Daymark").[56]

One of Daymark's key findings was "that, overall, MH's forecast of export revenue is reasonable, and reflects sound analysis of future system inflows, energy generation, export prices, and contract revenues."[57] In support of this key finding, Daymark offered the following observations:[58]

- The short-term and long-term export price forecasts are reasonable, and the low and high sensitivities reflect a reasonable range of market conditions;
- The export contract terms are appropriately reflected in the modeling and export revenue forecast;
- The inflow forecasting changes align with near-term and long-term energy modeling improvements, which have increased the ability to model system conditions and constraints; and
- Manitoba Hydro is projecting lower export volumes due to higher domestic demand, and lower export energy prices due in part to increased renewable development in the MISO market. In addition, the possible transition of MISO to a winter-peaking system lowers potential seasonal diversity exchanges. In combination, these suggest that maximizing net extraprovincial revenue may be more challenging than in the past.

Daymark concluded that Manitoba Hydro's forecast was reasonable, appropriate and

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[55] PUB Order 130/22, page 22.
[56] PUB-7, The retainer of Daymark and Scope of Work.
[57] DEA-2, Daymark Independent Expert Consultant Report, page 8, April 13, 2023.
[58] DEA-2, Daymark Independent Expert Consultant Report, page 9, April 13, 2023; DEA-4, Daymark Presentation, slide 38.

conservative. Daymark also encouraged Manitoba Hydro to actively monitor export markets for opportunities to seek premiums for its energy and capacity sales.[59] This is further discussed below in Section 6.12 & Section 6.13.

6.3. Forecasts of Export Revenue is Based on Improved Short and Long-term Modelling

Daymark Scope of Work Items #2, #4, #5, and #11 all relate to modelling used to prepare short and/or long-term net export revenue and generation costs forecasts, among other matters.

As explained by Mr. Gawne, Manitoba Hydro has made transformational improvements to its near-term inflow forecasting:

> *"This brings our forecasting methods to a level that is consistent with industry-best practices. These new models simulate the water cycle and use data on current basin conditions and forecasted weather to produce inflow forecasts which helps to reduce the short-term uncertainty to our inflow forecasts compared to purely statistical methods used prior to 2020 by Manitoba Hydro.*
>
> *To make this happen, Manitoba Hydro invested in its weather and water data networks, formalized data sharing agreements with partners in neighbouring regions, and leveraged the use of satellite-based information. This was made possible through years of participation in industry working groups, in collaboration with academia, other peer agency -- and other peer agencies."*[60]

Dr. René Roy, Roy Consulting, also opined on Manitoba Hydro's hydrologic modelling improvements:

> *"In my opinion, the approaches used up until now to forecast the inflows on short, medium to long terms is much appropriate. MH is spending*

[59] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023 page 9.
[60] Transcript May 16, 2023, pages 557-558, referencing Exhibit MH-30.

considerable efforts to implement widely their physically based model (WATFLOOD) using as inputs the most relevant weather forecasting products.

…

Not only do MH operators use appropriate forecasting tools, but they also contribute to their development through their involvement in and support of cutting-edge research projects concerning these tools and the inputs required for their use.” [61]

As part of its scope of review, in terms of the process for energy modelling, Daymark correctly summarized there is more to hydro system modelling than hydrology:

“so that was -- that was hydrology, which -- which is an interesting topic and an important topic in and of itself. But if that's where -- if that's where it ended, there'd be nothing to talk about here, because nobody turns their lights on with hydrology, with -- with flows of water, and -- and you're not selling flows of water down in -- into MISO or anywhere else.

It has to -- it was to be converted into energy. And so, the inflow process I just described, which is in and of itself, a complex modelling exercise is that an input into the energy modelling tools that they use to -- to produce -- to produce the amount of -- of energy that we'll later talk about, is -- is available for domestic use or -- or sale.” [62]

Manitoba Hydro explained the multi-year project to replace SPLASH with the PSR model suite:

“Manitoba Hydro undertook a multi-year project to replace its in-house long term production costing model (“SPLASH”) with an industry standard vendor model. Manitoba Hydro has implemented a suite of energy system modules by PSR, a leader in the development and support of decision

[61] MH-1, Application Tab 5, Appendix 5.4, Review of Manitoba Hydro’s Practices Regarding Inflow Forecasting for Operations and Financial Planning, as well as Climate Change Impacts to Future Streamflow Conditions, dated November 27, 2022, page 89.
[62] Transcript May 18, 2023, page 951.

support tools used in the energy and gas industry with a focus on hydropower systems. Manitoba Hydro's implementation of the suite of PSR modules is called the Generation system Simulation, Planning and Resource Optimization ("GSPRO") system and includes an integrated resource expansion planning module, stochastic optimization production costing module, and a high resolution generation dispatch module. GSPRO is used for long term planning studies and preparation of long term forecasts of generation and supply costs and extra-provincial revenues." [63]

Some of the key improvements of GSPRO over SPLASH was summarized in both Daymark's report and during the hearing.[64] In general, the new GSPRO system addresses useful life/obsolescence challenges, has the benefits of a third party software (reducing required time and people resources, avoids risks related to in-house developments, benefits from updates made for the wide base of software users in the industry), addresses the operational reality that future inflows are uncertain, has much greater time resolution, has the ability to model other resources such as solar, and has the capability to model more granular transmission topology.

Specifically related to energy modelling, Daymark found that Manitoba Hydro has made "significant improvements to its long-term dependable and opportunity energy modeling processes, incorporating advancements in data and availability, and transitioning to more advanced models to better reflect load shapes, transmission topology, inflow data, and operational constraints." [65]

Mr. Smith, Daymark expert consultant, summarized Daymark's overall findings related to modelling as follows:

"… the bottom line is, in both their inflow forecasting and their energy modelling, they have made significant upgrades to their methodologies, to their tools, and that those -- those data tools and techniques are

[63] MH-1, Application Tab 5, page 40.
[64] Transcript May 18, 2023, pages 953-957; DEA2, Daymark Independent Expert Consultant Report, April 13, 2023, page 19.
[65] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 21.

appropriate and lead to a -- a better, more robust and nuanced forecasting system." [66]

Manitoba Hydro's improved short and long-term modelling results in better forecasts of export revenues.

6.4. Both the Near-term and Long-term Price Forecasts are Reasonable

As discussed in Tab 4 (Amended)[67] of the Application, Manitoba Hydro uses a near-term net export price forecast (years one and two of the amended Financial Forecast Scenario), and a long-term export price forecast.

The near-term electricity price forecast (for fiscal years 2022/23 and 2023/24) is based on two sources: forward prices available from the [redacted] and a price forecast from one of Manitoba Hydro's consultant price forecasters who provides regular, monthly near-term price forecasts for the MISO footprint. **3a & 3b**

For longer-term net export revenue forecasting (years three and on of the amended Financial Forecast Scenario), Manitoba Hydro uses its long-term export price forecast derived from several independent price forecasts. The independent, long- term price forecasts are used to create Manitoba Hydro's consensus price forecast (i.e., reference case), calculated as the average price of all independent forecasts. Manitoba Hydro's electricity price forecast methodology is described in more detail in MFR 84.

6.4.1. Daymark Finds Both the Short-Term and Long-Term Export Energy Price Forecasts to be Reasonable

As part of its independent review, Daymark reviewed Manitoba Hydro's electricity export price forecast, including the low and high case forecasts, in the context of current MISO market conditions and factors influencing future MISO prices (Daymark

[66] Transcript May 18, 2023, page 957.
[67] MH-1, Application Tab 4 (Amended), Section 4.2.3 "Electricity Export Price Forecast".

Scope of Work #1)[68] and did not have any specific concerns about the reasonableness of any of the five consultant forecasts.[69]

Regarding the short-term forecast, Daymark determined that Manitoba Hydro's methodology produces reasonable base, low and high forecasts for use in its analysis and that the adoption of using two sources is an improvement.[70]

Regarding the long-term forecast, Daymark similarly found that Manitoba Hydro's methodology produces reasonable base, low and high forecasts and that Manitoba Hydro's approach to forecasting creates a reasonable range of scenarios that allow for an assessment of how near-term and long-term price uncertainty impacts export revenues.[71]

Manitoba Hydro submits that both the near term and long-term price forecasts are reasonable and can be relied upon for purposes of the amended Financial Forecast Scenario.

6.4.2. Trajectory of Long-Term Consensus Price Forecast is Now Declining

As discussed in Tab 4 (Amended)[72] of the Application, Manitoba Hydro has observed a change to the trajectory of the long-term Export Price Forecast from a long-term upward trend to a slight downward trend. Until recently, long term price forecasts anticipated that electricity prices were expected to rise faster than inflation. As was shown in Figure 4.7 of the Application and below, the 2022 Electric Price Forecast has a slightly declining long-term trend, indicating electricity prices are expected to rise slower than inflation.

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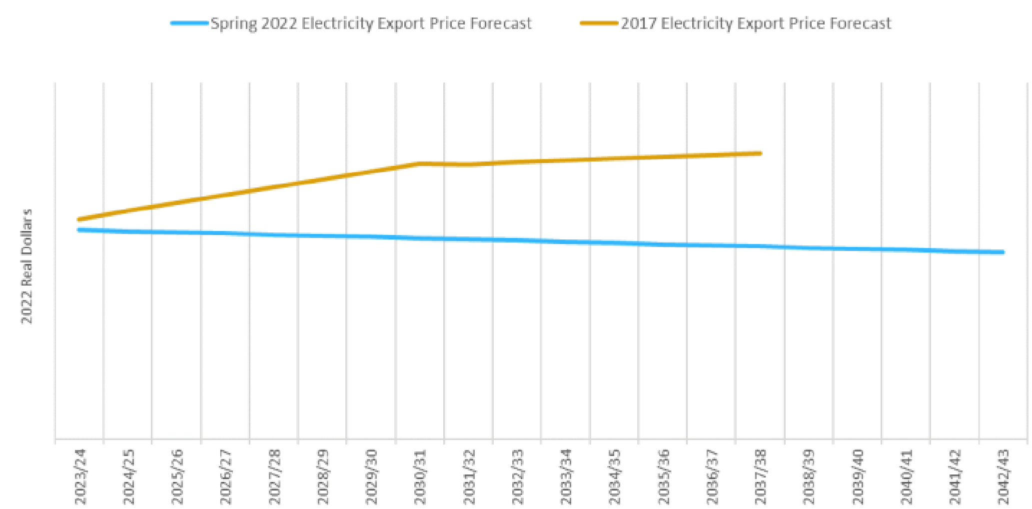
[68] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, May 17, 2023, slide 27.
[69] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 47.
[70] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, May 17, 2023, Slide 28; DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 46.
[71] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, May 17, 2023, Slide 29; DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 46.
[72] MH-1, Application Tab 4 (Amended), Section 4.2.3 "Electricity Export Price Forecast".

Figure 11

Figure 4.7 Trajectory of 2017 and 2022 Long Term Price Forecasts



The decline in real dollars can be attributed to decarbonization in the electricity sector such as the retirement of coal generation facilities, which is driving a build-out of wind and solar generation. These resources have near zero variable cost and will displace higher variable cost thermal resources and are anticipated to result in lower average market prices, putting downward pressure on Manitoba Hydro's export revenues.[73]

Part of Daymark's review included providing comments on the factors influencing the MISO market and trends that are affecting market prices (Daymark Scope of Work #8). Daymark's comments included "[l]ong-term market features significant uncertainty", and it's "[c]lear that the charge towards increased renewables will continue: Interconnection queue shows it, MISO transmission planning expects it, economic drivers and incentives support this transition." Daymark concluded by stating that for the current application, "uncertainty supports conservative assumptions."[74]

Further, Daymark found that Manitoba Hydro's assumption that export revenue from the MISO market is declining to be reasonable:

[73] MH-1, Application Tab 4, Appendix 4.2, page 1; MH-30, MH Export, Drought Management and Hydrology Presentation, May 16, 2023, slides 30-31.
[74] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, May 17, 2023, slide 15.

> "*Manitoba Hydro assumes export revenue from the MISO market is declining.* ***Is that reasonable? Yes. We expect that additional renewables will reduce energy market prices which will lower the energy market revenue. And that's even setting aside that Manitoba Hydro's expected load growth will reduce its potential supply of -- of export energy volumes****."*[75] [**emphasis added**]

6.4.3. Daymark Confirms MISO Market in Rapid Transition, and Diversity Assumptions are Reasonable

Manitoba Hydro discussed in Appendix 4.2, page 1 of the Application how low variable cost renewables displace higher variable cost thermal resources and are anticipated to result in lower average market prices, putting downward pressure on Manitoba Hydro's export revenues. Daymark confirmed that "[a]cross the U.S., including within the MISO region, the electricity sector is in a period of rapid transition, driven primarily by state and federal policies."[76] The extent of this transition is shown on page 28 of Exhibit DEA-2 and in the figure below, which shows the annual energy mix on the MISO market was projected to be 60% wind and solar generation by 2041, based on the MISO 2022 Regional Resource Assessment analysis. No intervener has offered any contradictory evidence that there is a large build out of wind and solar generation currently in progress in the MISO market.

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[75] Transcript May 18, 2023, page 925.
[76] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 24.

Figure 12[77]

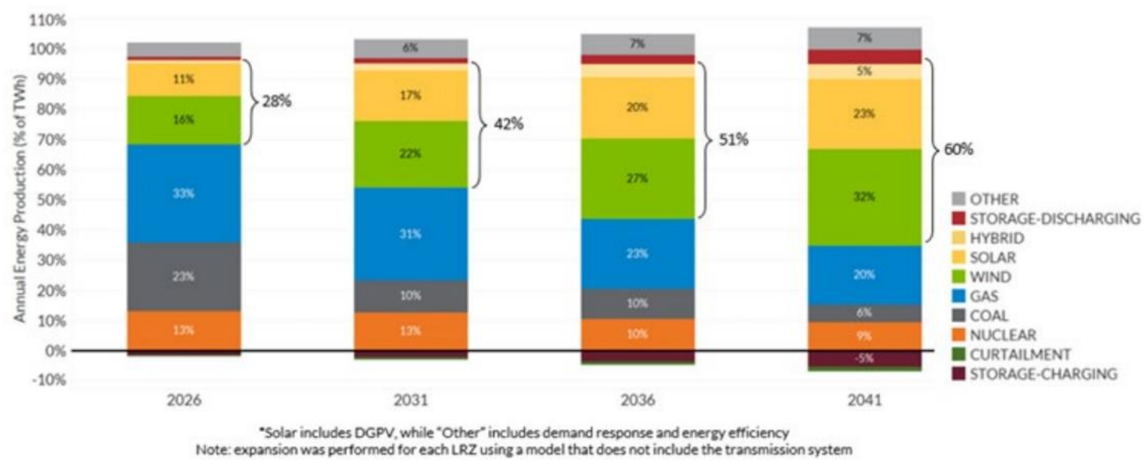

Figure 6. MISO 2022 RRA results, energy mix[23]

Daymark noted that "[e]lectrification of heat and transportation will change load patterns; high Northern MISO impact" and that "[i]f winter capacity becomes [a] planning constraint, utilities will add winter firm capacity, resulting in lower demand for MH summer seasonal capacity."[78] Manitoba Hydro also noted in Appendix 4.2 of the Application that as some neighbouring utilities anticipate the shift to become winter peaking, there may be less interest in future seasonal diversity arrangements, or summer capacity sales with Manitoba Hydro.[79]

As explained in Tab 5, page 39 of the Application, until recently, Manitoba Hydro assumed it would maintain a minimum level of seasonal diversity agreements with utilities in the Midcontinent Independent System Operator ("MISO") region that have traditionally experienced its peak load in the summer. However, the resource mix in the US is evolving with the buildout of solar, the anticipated electrification of heating, and higher winter planning reserve margins in MISO, so there is less confidence that seasonal diversity contracts will be available.

Daymark was asked to assess the reasonableness of Manitoba Hydro's assumption that a minimum level of seasonal diversity contracts will no longer be available

[77] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 28.
[78] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, May 17, 2023, slide 14.
[79] MH-1, Application Tab 4, Appendix 4.2, page 4.

following the expiration of its existing seasonal diversity contracts (Daymark Scope of Work #8). During direct examination, Mr. Bower acknowledged that Manitoba Hydro does not assume that diversity arrangements for capacity will be renewed and does not assume new capacity future sales, and concluded such assumptions are reasonable because “the disruption that's being caused by the seasonal capacity rules, load changes, and capacity build out and retirement means that assuming a minimum level of capacity sales would be highly uncertain.”[80]

Daymark provided additional detail supporting its assessment of Manitoba Hydro’s assumption on seasonal diversities and concluded:

> *“Thus, in general Daymark agrees with MH’s approach to assume, for budgetary purposes, that seasonal diversity arrangements will not be available in the future. There is enough uncertainty about future load conditions and market rules to cast doubt on whether MH would be able to find a willing counterpart for such an arrangement.”* [81]

6.5. Export Contracts are Expiring as Manitoba Load Grows

Most of Manitoba Hydro’s long-term dependable contracts will expire over the forecast period reducing firm contract export revenues. The decline in these contracts with time is primarily driven by the need for the associated energy and capacity resources to serve expected increases in the Manitoba load. In fact, the current portfolio of dependable long-term contracts is almost halved by 2030/31. Export contracts are forecasted to make up 49% of total exports in 2024/25, and as contracts expire that proportion will decline to 19% by 2035/36.[82]

Gross electrical demand in Manitoba is growing. As discussed in Tab 5 of the Application, Manitoba Hydro is expecting less overall energy usage, but higher peak demands compared to the projections included in the 2017 Electric Load Forecast. The Manitoba Net Load at Point of Supply is projected to grow by 351 MW between 2022/23 and

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[80] Transcript May 18, 2023, page 925, lines 12-21.
[81] PUB/DAYMARK I-8b.
[82] MH-1, Application Tab 5, Section 5.4, page 17.

2030/31.[83] Mr. Gawne explained that Manitoba Hydro, consistent with industry practice, plans to have sufficient resources available to reliably supply Manitoba and firm export customers consistent with its energy and capacity planning criteria that has been provided in Appendix 5.5 of the Application.[84]

Ms. Grewal spoke about the upcoming winter capacity constraints and the need to serve the growing Manitoba load, stating"[w]e will require additional capacity in Manitoba and, therefore, we would not have surplus green dependable capacity to sell to other parties because we will need that electricity and that generation here, plus other sources."[85] It is worth noting that the surplus situation is different for summer capacity, where there is excess summer capacity available not required by Manitobans.[86] However, as further explained in Section 6.11.3, the market for seasonal capacity is still evolving, and based on the initial MISO seasonal capacity auction results, there is limited upside potential summer capacity revenue at this time.

Mr. Gawne explained the 2022 Supply/Demand Scenario with new resources added, which indicated that long-term supply and demand are expected to remain in close balance, without long periods of material surpluses.[87] This is a shift from past experience where large hydroelectric generation investments resulted in prolonged periods of surplus dependable energy and capacity in both summer and winter, relative to Manitoba customers' needs enabling significant long term export contracts.[88] This is not the outlook today. However, although long-term export contract revenue declines over time, the revenue from the repatriated energy and capacity, valued at domestic rates, is accounted for outside of the Net Export Revenue forecasting process.

6.6. Firm Export Revenue Forecasts Confirmed by Daymark

As part of its scope of work, Daymark was asked to review the forecast export revenues for each export contract provided as part of MFRs 85 and 86 and confirm whether these forecast revenues are reasonable and are underpinned by the export contracts (Scope of

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[83] MH-1, Application Tab 10, MFR 43, Figure 1: Winter Peak Capacity Supply and Demand.
[84] Transcript May 16, 2023, pages 578- 579.
[85] Transcript May 15, 2023, page 251.
[86] MH-1, Application Tab 10, MFR 43, Figure 3: Summer Peak Capacity Supply and Demand.
[87] Transcript May 16, 2023, page 580.
[88] MH-1, Application Tab 5, Page 42.

Work #6).

Daymark reviewed both MFR 85 and MFR 86, which provided Manitoba Hydro's forecast revenues and sales volumes. Daymark also received a spreadsheet of workpapers from Manitoba Hydro supporting the MFRs, as well as copies of all export contracts. Daymark indicated that they reviewed the 15 export contracts to determine whether the contract terms (volumes, prices, duration) matched the assumptions used to prepare MFR 85 and 86 and reviewed the workpapers supporting the export revenue forecast in MFR 42 to confirm that the contract revenue assumptions were consistent.[89]

Daymark concluded that the export contract revenues developed by Manitoba Hydro for MFRs 85 and 86 were supported by the contract terms and were correctly represented in the MFR 42 Revenue forecast. Daymark also concluded that the forecasted contract revenue is reasonable. For those contracts with pricing terms that change over time, Daymark reviewed the pricing and concluded that Manitoba Hydro used reasonable escalation rates when developing MFR 85 and 86.[90]

6.7. The Supply/Demand Scenario Maximizes the Capability of Manitoba Hydro's Existing System, Includes Demand Response, and Proxy Resources that are Added Incrementally as Needed

A key assumption in the supply/demand scenario that underlies the net export revenue forecast and the financial forecast scenario is that the performance and capability of the existing system will be maintained through ongoing investments.

As stated in Section 4.2.5 of the Application and explained in greater detail in Section 6.10, based on the 2021 Electric Load Scenario and current planning assumptions, Manitoba Hydro's anticipated need date for new resources is 2030/31 based on sustained winter peak capacity deficits. Sustained annual dependable energy deficits appear starting in 2033/34.

Initial deficits were addressed by maximizing the capability of Manitoba Hydro's existing system through refurbishments and supply side enhancements, as well as demand

[89] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 48.
[90] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 51.

response. As stated in Section 5.9 of the Application, proxy resources were used to balance supply and demand, in this case wind power purchase agreements ("PPAs") for energy starting in 2033/34 and dispatchable natural gas-fired capacity resources with greenhouse gas offsets starting in 2038/39.

Manitoba Hydro believes these are lowest cost and reasonable assumptions to provide indicative generation costs in the latter portions of the Financial Forecast Scenario. These resources are added incrementally to follow load and do not result in large surpluses of capacity or dependable energy. No intervener provided alternative indicative generation costs.

Manitoba Hydro disagrees with the suggestion that, with the pressures of achieving net zero and eliminating GHG emitting natural gas turbines, the use of a natural gas turbine as the next available capacity resources was not appropriate. Manitoba Hydro's assumption of natural gas combustion turbines as a proxy dispatchable capacity resource for the second half of the 20-year Amended Financial Forecast Scenario was articulated by Mr. Turner during cross examination:

> *"MR. HAL TURNER: "I think the short answer is, yes. At this point there is no regul -- regulations federally or provincially that would preclude this type of resource. Our mandate is to be -- provide reliable electricity at the lowest cost. This is the lowest cost capacity resource. So, I believe it's appropriate to use. If at some point in the future regulations change or something like this is precluded, then of course we would consider something else. But given our mandate, I think the answer is, yes, it's appropriate."* [91]

Daymark was also requested to provide an opinion on the matter, and stated:

> *MR. JEFFREY BOWER: "… adding thermal for capacity purposes is not necessarily -- it continues to be a component of -- of resource plans even in regions that are expecting to decarbonize because using thermal resources*

[91] Transcript May 17, 2023, pages 880-881.

as -- as peaking resources only doesn't contribu -- contribute a lot of -- necessarily contribute a lot of emissions.

So it doesn't surprise me to see it -- see it in here, but again, we haven't reviewed as part of our scope their -- their planning assumptions in detail."[92]

Manitoba Hydro submits that basing the cost of a dispatchable capacity resource on a combustion turbine with greenhouse gas offsets, over the latter half of the 20-year Amended Financial Forecast Scenario, is a reasonable proxy to assume for the Financial Forecast Scenario.

6.8. Firm Export Contracts Have Been Optimized

In 2021, considering the evolving energy landscape, Manitoba Hydro performed a review of its existing export contracts to determine if these contracts were still providing the best value to Manitobans. The findings of the review were summarized by Mr. Karanwal: "…The conclusion of the reviews were that the contracts were performing well, compared to the MISO market, provide Manitoba Hydro with revenue certainty in an uncertain market, provide value in keeping Manitobans' electricity rates lower than they otherwise would be." [93]

The findings are further supported by the evidence that Ms. Sanclemente provided in her direct evidence as an update to the Application. In explaining the update to Figure 4 from Appendix 4.2, which compared the long-term export contract prices from 2012 to May 1, 2023, Ms. Sanclemente testified that opportunity prices have been significantly lower than export contract prices, on average, except for a few brief periods, such as the winter of 2021/22.[94]

For the purposes of the Net Export Revenue forecast, Manitoba Hydro's assumption that these contracts will remain in place, unchanged, until maturity is reasonable. Considering the testimony by Manitoba Hydro's witnesses and the review by Daymark, the PUB can

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[92] Transcript May 18, 2023, page 1077.
[93] Transcript May 16, 2023, page 574.
[94] Transcript May 16, 2023, page 573.

be confident that the forecast contract revenues are reasonable and can be relied upon in setting rates for Manitobans.

6.9. Opportunity Energy Revenue Projections Based on Average of All Flow Conditions

As part of its scope of work, Daymark was asked to review and assess for reasonableness Manitoba Hydro's forecasts of exportable surplus energy and capacity by on-peak and off-peak period, taking into account expected inflow conditions, reservoir levels, and tie line capacities for both the test years as well as the next twenty years as provided in PUB Minimum Filing Requirement 42 (Scope of Work #6).

Daymark concluded that the export energy volume forecast was reasonable. [95] Daymark also stated:

- Exportable surplus energy is the result of the energy modeling processes previously described (HERMES and GS PRO).
- Energy export volume is the energy supply (produced by flow cases) less domestic load and firm sales.
- As previously discussed, Daymark concluded that the energy modeling tools produce reasonable outputs based on the flow cases and simulations of the system.[96]

The basis of the export energy volume forecast is the expected value from the 40 years of inflow cases for 2023/24, followed by the average calculated from the full 100+ year record for the remainder of the analysis period. Daymark concluded that this approach was reasonable, noting the significant benefits to the increased spatial and temporal data granularity available in the 40-year record that can be used to better reflect short-term conditions with its enhanced modelling tools. Further discussion on the 40-year record can be found in Section 7. Daymark also acknowledged Manitoba Hydro's commitment to continuous review and evaluation to determine the most effective analytical methods moving forward.[97]

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[95] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 54; DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, slide 35.
[96] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, slide 35.
[97] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 21.

6.10. Only a Sliver of Surplus Annual Capacity Available until 2030/31

The Manitoba Net Load at Point of Supply is projected to grow by 351 MW between 2022/23 and 2030/31.[98] This load growth will be largely served by generation capacity which is currently being used to serve export contracts expiring before 2030/31. The anticipated need date for new capacity resources is 2030/31 based on sustained winter peak capacity deficits. Beyond 2030/31, new annual capacity resources are required and there is no winter/annual capacity surplus available for export. As explained in Manitoba Hydro's response to Coalition/MH II-101, based on the planning assumptions provided in Figure 1 Winter Peak Capacity Supply and Demand Table of MFR 43, the average amount of winter capacity surplus between 2022/23 and 2029/30 is only 2.25% of the Total Power Resources.

This matter was explored further during cross examination of Midgard Consulting Incorporated ("Midgard") regarding its statements claiming there is significant surplus:

> *"MR. MATTHEW GHIKAS: I think -- I think part of your answer there I want to zero in on is you haven't looked at the data to determine -- to back up your statement that there is suff -- that there is significant surplus in the system, have you?*
>
> *MR. CHRISTOPHER OAKLEY: I haven't looked at the data. I've looked at the evidence that was provided.*
>
> *MR. MATTHEW GHIKAS: Okay.*
>
> *MR. CHRISTOPHER OAKLEY: I've -- I've looked at what Hydro says they do. I've looked that they said that they don't really need Pointe du Bois until 2032. I take them at their word."* [99]

In fact, and contrary to Midgard's understanding, Manitoba Hydro's data and evidence demonstrates that without Pointe du Bois, capacity deficits would first occur in 2027/28

[98] PUB/MH I-45a; MH-1, Application Tab 10, MFR 43, Figure 1.
[99] Transcript May 25, 2023, pages 1798-1799.

and sustained deficits would commence in 2029/30.[100]

6.11. Uncertainty in the MISO Market Outlook Supports Manitoba Hydro's Assumptions

The assumptions made by Manitoba Hydro as a result of the uncertainty in the MISO market are supported by Daymark. With respect to its review of the MISO market outlook, Daymark noted that long-term market features significant uncertainty, and also noted that the evolution in the MISO market could create new or expanded opportunities, such as new ancillary market products. Daymark concluded that the uncertainty in the MISO market supports the use of conservative assumptions in the GRA.[101]

As noted by Mr. Bower on behalf of Daymark, "given all this uncertainty, we essentially conclude that for the GRA, the conservative assumptions related to the opportunities for MISO sales are appropriate based on what Manitoba Hydro can know today about products and pricing."[102]

6.11.1. No Near-Term Prospect for New Ancillary Service Products

Manitoba Hydro already supplies ancillary services into MISO through innovative market mechanisms that allow Manitoba Hydro to maximize the value of its dynamic/flexible system in its MISO market interactions. Associated revenues are included in Manitoba Hydro's financial forecast scenario provided in Appendix 4.1 (Amended) of the Application. This was explained in the MIPUG/MH I-16 and the preamble to MH/Daymark I-1:

> *"In MISO's Real Time market Manitoba Hydro utilizes an External Asynchronous Resource (EAR) to provide the MISO Market with energy and ancillary services. (Background: External Asynchronous Resources (EARs) represent an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is represented within the MISO Region through a Fixed Dynamic*

[100] COALITION/MH II-103a, page 2.
[101] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, slide 15.
[102] Transcript May 18, 2023, page 924.

Interchange Schedule. EARs are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid. Qualified EARs are eligible to provide Regulating Reserve, Spinning Reserve, Supplemental Reserve, and Short-Term Reserve in addition to Energy."[103]

Manitoba Hydro concurs it is possible that new ancillary service market products could be developed, as suggested by Daymark. However, such new products have not yet been defined and therefore cannot be valued. It could be many years through the MISO stakeholder engagement and FERC approval processes before any such new ancillary service products come to fruition.

Manitoba Hydro has participated in MISO's ancillary service market since it opened in 2009. As noted in Manitoba Hydro's response to PUB/ MH I-46 d), ancillary services is not a major source of revenue for Manitoba Hydro. The MISO 2021 State of the Market report at page 4 states "[t]he ancillary services component contributed on $0.13/ MWh."[104] Battery/energy storage resources are also providers of ancillary services. As discussed in Manitoba Hydro's response to PUB/MH I-45d, about 96% of the potential 289 GW of resources in the MISO generation interconnection queue are renewable or storage resources. At this time, Manitoba Hydro does not believe there is much potential upside in ancillary service revenue.

6.11.2. No Near-Term Prospect for New Premium for Clean, Dispatchable Resources

Daymark noted that "there is significant change occurring in MISO and significant need for clean firm energy (for capacity and for balancing) projected over time, potentially driving an increase in the market value of MH's products."[105] Daymark went on to state:

"It is likely that as the MISO market evolves, there will be some method for generating a premium price for Manitoba Hydro's clean, dispatchable resources. However, at this time it is highly uncertain

[103] MH/Daymark I-1, page 2.
[104] AMC/DEA I-2.
[105] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 9.

what those mechanisms will be, or what the monetary value will be. Additionally, as discussed in Section III, it is unclear whether the MISO market changes will produce opportunities that align with MH capabilities." [106]

There is no mechanism and therefore no realistic expectation of any additional export revenue due to a "clean and dispatchable" resource premium in the next several years. There are currently no proposals for new products in MISO that would provide additional export revenue for a "clean and dispatchable" product, and if any new "clean and dispatchable" resource premium was achieved, Manitoba Hydro would have to compete with heavily subsidized MISO based resources. As such, not including any value for such a speculative "clean and dispatchable" resource premium for financial forecast scenario is a reasonable assumption.

6.11.3. Seasonal Capacity Market/ Planning Resource Auction is Still Evolving

While there is some potential to sell surplus summer capacity under a bilateral contract there is significant uncertainty and numerous barriers to achieving significant value to surplus summer capacity.

"MISO determined they need a much greater (41.2%) Planning Reserve Margin in Winter 2023-24 versus a more typical 15.9% in the summer of 2023."[107]

"MISO noted the planning reserve margins vary across the seasons "largely driven by the seasonality of resource mix/ performance and load levels". This much higher winter planning reserve margin has created huge uncertainty in the potential market for seasonal capacity, and there has been significant stakeholder pushback on this finding."[108]

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[106] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 63.
[107] PUB/MH I-45c.
[108] PUB/MH I-48a.

The results of the first MISO seasonal Planning Resource Auction ("PRA") were posted by MISO on May 17, 2023. The next day, Daymark gave the following update during its cross examination:

> *"MR. JEFFREY BOWER: It's the first -- yeah, hot off the presses. And it's the first -- the first auction that they've done for the four (4) different seasons. And Doug may have to -- or Mr. Smith may have to support me with some of the details, but - - but all of the regions were -- were quite low, especially in Northern MISO. So, even though in the 2022/'23 auction they were up at two hundred and thirty-six dollars ($236) per megawatt day, which is quite high, in this auction that the results just came out yesterday, they were down to five dollars ($5), something like that.*
>
> *MR. DOUGLAS SMITH: Yeah. Low as two (2) in the winter, ten (10) in the summer, ten (10) and fifteen (15) fall and winter, all very low for all zones except for the zone 9, which is Louisiana and Texas."* [109]

To summarize, in the 2023/24 MISO Seasonal Planning Resource Auction, the clearing price for summer seasonal capacity in MISO North was "very low" at $10/ MW-day or $900/ MW for a 90-day summer season. At this price, 100 MW of surplus summer capacity would be worth about $90,000 in annual revenue.

In its direct evidence presentation, Daymark concluded that Manitoba Hydro's export capacity volume forecast was reasonable and Daymark agrees with the assumption of no new capacity sales for GRA purposes."[110]

6.12. Former Long Term Dependable Product Premium No Longer Exists

Prior to 2017, Manitoba Hydro applied a Long Term Dependable Product Premium to a bundled product of dependable energy and generation capacity which was assumed to be sold on a long-term (5 or more years) firm basis. The Premium was over and above the

[109] Transcript May 18, 2023, page 1016.
[110] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, May 17, 2023, page 36.

value of the capacity and energy products based on the consensus price forecast and Manitoba Hydro's ability to leverage what was once an almost unique fixed price carbon-free product in the MISO market.

The Written Final Argument of Manitoba Hydro in the 2017/18 & 2018/19 General Rate Application noted, starting at page 115, that "Manitoba Hydro is no longer the only renewable option for potential customers seeking a carbon free renewable product at a fixed price. Competition from low cost renewables does not support a premium for long-term dependable products at this time, and Manitoba Hydro expects the situation is unlike[ly] to improve in the future as wind and solar costs are falling, even as subsidies for wind generation are being phased out."

Since the 2017 GRA, wind generation subsidies in the US/ MISO market were not phased out, and in fact new subsidies for wind, solar and energy storage have been implemented in the US: "Since the release of the Spring 2022 Electricity Price Forecast and MISO RRA analysis, new US legislation was passed which will accelerate additions of non-emitting generation, natural gas-fired generation with carbon capture and storage, and energy storage. On August 16, 2022, US President Joe Biden signed the Inflation Reduction Act ("IRA") that includes US$369 billion for energy and climate change initiatives." [111]

When the premium concept was explored further by the PUB, Daymark summarized that Manitoba Hydro should continue to engage with MISO and other stakeholders to find opportunities, "[b]ut for budgeting purposes, we do not believe that including any opportunity premium in a reference case is supported by the facts and activity within MISO activities or US policy."[112]

More importantly, as explained in Section 6.10, there is little (or a sliver of) surplus annual generation capacity available and there is a need for new Manitoba resources anticipated in the 2030 time frame. This means there is no surplus past 2030.

6.13. Manitoba Hydro Continues to Explore Export Opportunities

For decades Manitoba Hydro's relationships in the wholesale electricity markets outside

[111] MH-1, Application, Tab 4, Appendix 4.2, page 3.
[112] PUB/DAYMARK I-1, page 3.

of Manitoba have been critical to its economic and reliable service to customers, providing significant revenues when supply exceeds Manitoba's needs, and a dependable supply when Manitoba Hydro is experiencing drought or emergency conditions. Further, these relationships have enabled access to the neighboring electricity markets providing Manitoba Hydro with the ability to sell into or buy from them without undue trade barriers or market rule restrictions.

As described in Manitoba Hydro's response to PUB/MH I-45a-d, finding new seasonal export contracts is becoming more challenging because the resource mix in the US is evolving with the buildout of solar, the anticipated electrification of heating, and higher winter planning reserve margins in MISO. However, in spite of these challenges, there is continued importance of wholesale customers and the electricity markets to Manitoba Hydro. Mr. Karanwal indicated that Manitoba Hydro intends to remain active in both areas to ensure Manitoba Hydro reaps ongoing value from being interconnected: "[a]lthough we have limited excess firm power available, there are always opportunities for entities to work together for mutual benefits, such as the sharing of surplus seasonal capacity, which could defer the needs for new capacity resources by both sides." [113]

This was also confirmed in Daymark's report, finding that there is potential for incremental revenue if Manitoba Hydro can monetize its excess summer capacity.[114] However, until the details of any specific new transaction becomes known, it is premature to try and guess the magnitude of the potential revenues that could occur as a result. Daymark addressed this further in its presentation, stating: "Daymark agrees with the assumption of no new capacity sales for GRA purposes."[115]

6.14. Export Revenue Forecasts Assume Assets Continue to Perform at Current Levels

Manitoba Hydro cannot achieve the revenues projected in Figure 4.2, Electric Operations Statements, of the Application (initial years Forecast Extraprovincial revenues of $1.283 billion for 2022/23 and a Preliminary Budget projection of $1.153 billion for 2023/24) if its revenue- producing generation assets are "permitted to degrade further".[116] Even if

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[113] Transcript May 16, 2023, pages 574-575.
[114] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 58.
[115] DEA-4, Daymark Energy Advisors, Export Revenues and Drought Operations Presentation, May 17, 2023, page 36.
[116] MH-24, MH Rebuttal Evidence, page 71.

forced generation outages do not cause loss of load events ("system outages"), they are likely, under most water conditions, to result in some sort of negative impact to net export revenue through lower hydro generation.

Mr. Turner highlighted the importance of this assumption in his testimony:

> *"A significant point I would like to make is that our net export revenue forecast assume that the performance and capacity of the existing system will be maintained through ongoing investments. That is, we are assuming that we will be able to properly invest in existing generation, transmission, and high voltage direct current systems as they age so they continue to produce electricity and deliver electricity to our customers at a high level of reliability."*[117]

Put simply, degradation of system performance will degrade revenue.

7. MANITOBA HYDRO'S USE OF HISTORIC HYDROLOGIC RECORDS AND INFLOW FORECASTING IS STATE OF THE ART

Following the approval of Manitoba Hydro's 2021/22 Interim Rate Application, in Order 9/22, the PUB noted the importance of flow forecasting to manage drought risk and requested additional expert evidence to be filed with the GRA examining Manitoba Hydro's hydrological forecasting practices and use of the most recent 40 years of water flow data to model reservoir and generation operations for the purposes of short-term financial projections.

To address the PUB's request, Appendix 5.4 was filed as part of the current Application and summarized several topics related to Manitoba Hydro's inflow forecasting processes and supporting hydrological studies. This document was reviewed by Manitoba Hydro's independent expert, Dr. René Roy, and was also shared and discussed with Daymark. Among other items, Manitoba Hydro's inflow forecasting processes and adoption of a 40-year flow record for short-term flow forecasting and energy operations were reviewed. As summarized in their respective reviews, both Dr. Roy and Daymark support and endorse Manitoba Hydro's inflow forecasting process and use of historic hydrologic

[117] Transcript May 16, 2023, page 545.

records.

7.1. Manitoba Hydro's Water Supply Forecasting Tools, Methods, and Procedures are Standard and Reflect Industry Best Practice

In Dr. Roy's review letter to Manitoba Hydro, he states:

> *"… in the fields of Meteorology and Hydrology, Manitoba Hydro can be considered, according to the CEATI Maturity Matrix a 'Leading Edge Organization', i.e. developing, trialing and implementing new technology, methods and systems. This Maturity Matrix developed by CEATI in 2016, is utilized as an illustrative communication tool and an effective means to document and compare the activities performed by an organization with the best known practices."* [118]

> *"… with respect to the reasonableness of the technical work presented here by MH, I consider that the work done by Manitoba Hydro to improve the forecasting tools, the baseline data required to populate these tools, and the approaches to be used in making inflow forecasts for the various time horizons are at the leading edge of what is being done in the hydroelectric industry."* [119]

In response to PUB/MH I-170a-c, Manitoba Hydro expanded upon its participation with the CEATI Hydropower Operations Planning Interest Group,[120] consisting of members from about three dozen major hydroelectric utilities and water management related agencies. Through this involvement, Manitoba Hydro ensures its inflow forecasting and reservoir management practices and technology are informed by current industry knowledge and best practices.

Daymark provides a similar assessment to Dr. Roy in both its filed evidence and oral testimony:

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[118] MH-1, Application, Tab 5, Appendix 5.4, page 91.
[119] MH-1, Application, Tab 5, Appendix 5.4, page 91.
[120] www.ceati.com/programs/hydropower-operations-planning, The Centre for Energy Advancement through Technological Innovation.

"Based on our review, we find that the MH has made significant advances in its inflow forecasting methodologies to improve the near-term forecasting using the PBIF process. MH is continuing to phase in more PBIF locations, and the Corporation's experience so far indicates that the continued work on the hydrological models will improve forecasting outcomes in the future." [121]

"We did some independent assessment of the tools that they chose, the approaches that they took, and those tools have a strong reputation in the industry. They're used widely around the world … collectively they represent a strong platform for the updates and methodologies that they're going through now and the planned and potential upgrades to come." [122]

7.2. Existing Weather Forecast Products are Not Reliable

Manitoba Hydro has noted in this Application, as well as past GRAs, the high degree of variability of inflows to its hydroelectric generating system and the lack of reliable long-range precipitation forecasts. Both factors contribute to the high degree of uncertainty in future water conditions and Manitoba Hydro's limited ability to forecast the future timing and severity of drought events. In Order 9/22, the PUB indicated an interest in determining what, if any, additional drought forecasting options may exist to mitigate risk.

Appendix 5.4 of the Application summarizes the uncertainty and limited skill of existing seasonal to interannual weather forecast products, as well as the operational challenges that have been faced by other agencies while attempting to implement these types of forecasting products. While the current forecast products available are not reliable enough for operational use, Manitoba Hydro remains committed to following advancements in this field and participating in applied research on inflow forecasting.

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[121] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 21.
[122] Transcript May 18, 2023, page 941.

"This [OPBIFF] has helped inform [near] term decisions in our operations, however, it's impossible to reliably forecast precipitation and river flows over the multiple months in the future, which will ultimately impact our hydro-electric generation for the next year and when we're forecasting that export revenue. Seasonal to inter-annual weather forecast products, they do exist, however their skill and reliability, particularly for the watershed that supplies our system [are] not at the level we can rely upon them." [123]

"Despite significant improvements, as of today, longer term flow forecast (monthly to seasonal) suffers from a lack of skill with respect to precipitation forecast. Nevertheless, since these weather forecast products could provide better results in the future, it is important to stay informed of the progress to take advantage of these inputs to improve longer term flow forecast." [124]

"MH is following closely the potential improvement of forecasting systems published recently and/or discussed with other hydroelectric utilities through their involvement in different forums and research projects. They investigated the skills of long-range future precipitation which appears to be limited for the moment, at least for the region of interest. MH is also aware and actively participating in research projects dedicated to improve inflow forecasts (ensemble forecasts, use of new and improved long-range weather forecasts, Artificial Intelligence tools, etc.)." [125]

7.3. Manitoba Hydro's use of both Physically-Based and Statistical Hydrologic Forecasting Methods to Determine Future Inflow Conditions is Appropriate and Consistent with Industry Practice

Both Dr. Roy and Daymark have confirmed through their respective reviews that Manitoba Hydro's use of both physically-based and statistical methods is a reasonable and standard approach to assess and forecast future water supply conditions:

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[123] Transcript May 16, 2023, pages 559-560.
[124] PUB/MH I-178a, Dr. Roy response, page 3.
[125] MH-1, Application, Tab 5, Appendix 5.4, page 89.

"It is recognized that physically based models could improve the inflow forecasts in many circumstances, nevertheless, it should be mentioned here that MH is also using appropriately the statistically based tool still useful on the longer term and more specifically for large watershed. Moreover, as pointed out in the document, statistical approach will remain useful for ungauged basins and sites affected by winds. Not only do MH operators use appropriate forecasting tools, but they also contribute to their development through their involvement in and support of cutting-edge research projects concerning these tools and the inputs required for their use." [126]

"… both statistical and physical approaches in water resources management have their advantages and withdraws. It is common in the Hydropower Industry to rely on both approaches, generally by using physical hydrological models for short to mid-term time horizons and statistical models for longer term uses… Since both approaches could provide most valuable information with respect to flow forecasting, it is normal and common in the Hydropower industry to take advantage of both approaches." [127]

"PBIF produces higher quality forecasts versus the old statistical basis. Because each drought in MH's history has been different, utilizing the 40 year ensemble modeling with PBIF based on actual reservoir starting points provides an improved picture of the range of outcomes that represent energy production uncertainty. Any historic drought within the PBIF timeframe could be the most constrained hydrological case depending on starting reservoir conditions and near-term precipitation expectations. This is an improvement over the pure statistical forecast used for previous short-term modeling needs." [128]

"[T]he real take away is it is a reasonable approach to transitioning to a new methodology that gives them much more granularity and ability to

[126] MH-1, Application, Tab 5, Appendix 5.4, page 89.
[127] PUB/MH I-178a, Dr. Roy response, page 2.
[128] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 81.

understand how localized flow conditions lead to -- lead to energy production, while still providing for a method that captures as much of the variability and uncertainty, because you can't -- no matter what you think you know today, you don't really know what -- what the weather's going to be like next year or next -- next week, next month, you know, there's -- there's -- so they needed to have that -- that flexibility, that uncertainty, but they needed to modernize, to better capture the available data, and -- and we believe that this was a reasonable [choice]." [129]

7.4. Manitoba Hydro's use of a Shortened 40-year Record for Short-term Budgeting is Justified and is an Improvement Over the Past use of the 100+ Year Record

In the 2021/22 Interim Rate Application, Manitoba Hydro advised the PUB of its transition to using the most recent 40 years of water flow data to model its reservoir and generation operations and translate that information into its short-term financial projections from the previous practice of using the entire 100+ year flow record. This transition was done to better align historical records with Manitoba Hydro's modernized forecasting tools, ultimately resulting in a better projection of forecasted short-term inflow conditions. The enhanced spatial resolution of the 40-year record also permits the modelling of upstream reservoirs including the impact of current storage levels and better reflects short-term inflows into the Manitoba Hydro system based on the most current operating rules and priorities. Manitoba Hydro provided a detailed explanation of its rationale in making this change in the 2021/22 Interim Rate Application IR Coalition/MH I-1a-d; however, in Order 9/22, the PUB requested that this change be further explored as part of the General Rate Application.

Manitoba Hydro filed its review assessing the differences in hydrological variability represented by various record lengths.[130] Using multiple methods, the study concluded that the most recent 40-year period captures over 95% of the hydrologic variability contained in the full 100+ year flow record.

Both Dr. Roy and Daymark reviewed Manitoba Hydro's materials, held discussions with Manitoba Hydro staff, and independently concluded that the transition to the shortened

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[129] Transcript May 18, 2023, pages 947-948.
[130] MH-1, Application, Tab 5, Appendix 5.4, Section 5.

40-year record is justified, is an improvement over the previous method, and contributed to Manitoba Hydro's effective management of operations through the 2021 drought:

> *"MH's move to a 40 year hydrology (and their use of hydrology and forecasting tools in general) was effective and produced a measured but increasingly strong response to the risk of further drought conditions."* [131]

> *"Regarding the specific question concerning the transition to the 40-year flow record from the 100-year record for the budget year, we find that MH's justification for this change is satisfactory. There are significant benefits to the spatial and temporal data granularity in the 40-year record, as discussed above. MH recognizes the tradeoffs between the two approaches and appears committed to continuous revaluation of its approaches and methods to determine the most effective analytical methods."* [132]

> *"...the bottom line is, in both their inflow forecasting and energy modelling, they have made significant upgrades to their methodologies, to their tools, and that those – those data tools and techniques are appropriate and lead to a – a better, more robust and nuanced forecasting system. And with respect to the forty (40) years, keeping in mind that forty (40) years is required for all of that to happen, we found that the justification for all the change is satisfactory. It's appropriate to move to that. It is, from our understanding, something that Manitoba Hydro plans to continue to assess over time as to whether forty (40) continues to be the right number, or whether, as new data occurs, whether there's opportunity for continued growth."* [133]

> *"As discussed in this document, the methods being used to analyze the optimal record length is a blend of academic and pragmatic approaches that offer unique perspectives and data insight. From the reviewer's perspective, looking at results issued from these four different approaches*

[131] DEA-2, Daymark Independent Expert Consultant Report, page 10.
[132] DEA-2, Daymark Independent Expert Consultant Report, page 21.
[133] Transcript May 18, 2023, pages 957-958.

brings robustness and increases the confidence in the findings. You also provided simple examples to understand better the strengths and weaknesses of the different metrics. These examples are most instructive to understand the approaches. It should be highlighted that the presentation of the results is very smart, extensive and clear. Considering relying only on most recent years of record (exercise being done or under evaluation in many hydropower utilities) is crucial, given the evolution of the hydrometeorological conditions and the difficulties associated with the inflow estimation at the very beginning of the record." [134]

8. MANITOBA HYDRO'S WATER AND ENERGY MANAGEMENT PROCESSES ARE STATE OF THE ART, DROUGHT OPERATIONS WERE REASONABLE

8.1. Overview

Drought is recognized as a significant risk to Manitoba Hydro and is a key focus to its energy operations planning and long-term planning. Manitoba Hydro's system is consistently managed to well-established priorities that have been put in place to ensure that, above all else, drought does not become an emergency. While the 2021 drought resulted in negative financial impacts, Manitoba Hydro was effective in guarding against the much larger and potentially catastrophic societal and economic consequences that could have occurred, had the expertise of many not been available or the proper tools and procedures not been in place.[135]

Manitoba Hydro's response to PUB/MH I-168a-c addressed lessons learned from the 2021 drought and whether those differed from those learned after the 2003 drought. Manitoba Hydro also listed learnings from the 2003 drought and other developments that contributed to its success in managing the 2021 drought, noting staff who were involved in energy and export operations during the 2003 drought applied their experience and learnings while managing the 2021 drought. Learnings from the 2003 drought also partly contributed to putting in place numerous other contractual, system, process, operational, and technological capabilities, which are summarized in Manitoba Hydro's response to this IR.

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[134] MH-1, Application, Tab 5, Appendix 5.4, page 90.

[135] MH-1, Application, Tab, 3, Appendix 3.2, Section 1.1, page 2; MH-1, Application, Tab 5, Appendix 5.3, Section 3.2, page 3.

8.2. Manitoba Hydro's Water and Energy Management Processes are Documented, Routine, and Consistent Across all Flow Conditions

Following the 2021 Interim Rate Application, the PUB summarized its understanding of Manitoba Hydro's operations in relation to drought: "Without reliable long-term forecasting, Manitoba Hydro must use its judgment as to when to switch its operations from seeking to maximize its extraprovincial revenues to preserving water for energy reliability purposes for domestic and firm export customers."[136]

Manitoba Hydro's reservoir and energy management decisions, including drought operations, are guided by well-established priorities that apply under the full spectrum of hydrologic conditions ranging from flood to drought. Use of these priorities, combined with approved energy operations planning assumptions, was explained by Mr. Gawne:

> *"These priorities apply under all water conditions. For example, in a flooding condition, we may have to forego economic operations to minimize high water level impacts on our stakeholders. At the other end of the water supply spectrum, drought, Manitoba Hydro's operations may be governed by conserving energy reserves to protect our – protect storage for continued drought."* [137]

Water conditions can affect the degree to which operating priorities drive decisions, however Manitoba Hydro doesn't rigidly "switch" from one "mode" or operating priority to the next. For example, Manitoba Hydro is always monitoring its storage conditions and ensuring firm demand can be met if drought conditions develop, consistent with the energy supply priority. As drought conditions develop, and storage levels reduce, the relative value of storage increases and the economics of the operation guide decisions towards conservation. Energy supply constraints are always considered, but they may not always be binding. Similarly, citizenship concerns are always considered, regardless of water conditions. This was confirmed in Daymark's report:

> *"In general, MH does not transition to any sort of alternative operations process upon water conditions deteriorating beyond a certain point.*

[136] PUB Order No. 9/22, page 87.
[137] Transcript May 16, 2023, page 554.

Rather, the Corporation's operational response to droughts should be thought of as an extension of normal operations wherein it pursues the objective of economic maximization within a set of constraints that are documented in their procedures and used daily. The challenges of operating the system change as system hydrology does, but the framework, which outlines the operational priorities and constraints under which the teams operate, does not change, regardless of whether the system is flush, is in drought, or is anywhere in between."[138]

With respect to detailed documentation or rules to cover the multitude of possible operating situations, complex considerations cannot be fully codified in a model, nor can procedures for every situation or scenario be fully documented. Therefore, operations planning requires routine and regular collaboration with many experts and, at times, involvement of executive. Daymark summarized these complexities at the hearing:

"…for the delivery of power, there are -- because of this complexity, there are often competing priorities that -- that can necessitate hard choices that Manitoba Hydro has to make. There are many stakeholders that are interested in – in how Manitoba Hydro operates the system, and they have competing priorities in terms of – of how they view or use or see the utility of the water."[139]

"But the -- but some of the constraints are simply too complex to easily convert to a set of inputs into a -- a tool -- into a dispatch tool. And so it is important to have this post-processing time to look at the results and to apply their professional judgment and their expertise across this broad range of -- of -- of teams within the organization to ensure that they are best meeting the -- their mandate which is -- which is to economically manage the system given those priority constraints."[140]

The citizenship concerns priority recognizes how Manitoba Hydro's operations can impact the waterways and their users. Specifically, the priority reads:

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[138] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 77.
[139] Transcript May 18, 2023, page 974-975.
[140] Transcript May 18, 2023, page 980.

"The operation of the system will be planned in a manner that minimizes significant adverse impacts of operations on other resource users and the environment. If adverse impacts cannot be avoided, Manitoba Hydro will provide notice to affected stakeholders. How the power system is operated must be tempered with respect for the priorities of others."[141]

This priority has linkages to all other priorities, including customer reliability and long-term economics. And these priorities are considered at all times as explained by Mr. Turner:

"That, and that we have to consider all of them. We think about all of them all the time. There may be times when we're less worried about some and more worried about others. There's going to be times when we're not worried about -- may -- maybe safety isn't an issue whatsoever, but the team is thinking about all of these things in totality." [142]

The priorities are top of mind under all water conditions. Similarly, much of the processes and procedures are applied under all water conditions. Daymark confirmed this and stated that Manitoba Hydro "does not operate its system in a fundamentally different manner during drought."[143] Daymark further confirmed that the consistent approach was a benefit in response to a question by Vice-Chair Kapitany:

"VICE CHAIR KAPITANY: Mr. Smith, just before you go on to hedging. I -- I didn't see it in your slides, but I read it in your report, and I think Manitoba Hydro said it as well, that they operate the system the same under all water conditions, including adverse water, and I just wondered, from your experience with other utilities, is that a normal process?

MR. DOUGLAS SMITH: Yes. I -- I -- I think that is the -- the process -- the process not changing is - is -- is a benefit. It is a strong -- you -- you do not want to have to stand up an entirely different process when you fall -- when you fall into different conditions. You're not -- your team isn't used to doing

[141] MH-1, Application, Tab 5, Appendix 5.3, Section 4.2.4, page 7.
[142] Transcript May 16, 2023, page 676.
[143] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 9.

it that way. You're -- you're -- you're adding additional risk. So, decisions will be different, right, different -- different pressures will mean different decisions at any given time, whether you're in flood, whether you're in drought, whether you're just humming along, but, if your process remains the same, then you are far more likely to be able to lean on it and follow it when you're under duress, and -- and I think we should all be clear that, whether it's Manitoba Hydro dealing with drought or it's Texas dealing with a storm in the middle of winter, or -- or any other utility, it is duress for these people. They -- they are operating a very complex system that has very real life consequences for -- for their customers and it is a difficult situation. When you are there, you want to be doing the same thing you've always done. You want to be doing it in a way that you are used to doing it. So, I -- I -- I would consider that a -- a benefit and a normal practice for utilities."[144]

Mr. Gawne testified as to how Manitoba Hydro's operating priorities are applied as drought conditions develop and how Manitoba Hydro's reservoir release decisions are made based on a range of potential flow conditions.[145]

8.3. Communication and Executive Oversight are Integral to Manitoba Hydro's Water Management

At both the Interim Rate Application hearing and in this Application, there has been interest in how water and energy supply conditions are communicated to executive and specifically, how executive is involved in decision making during drought conditions.

In terms of reporting and communicating, Manitoba Hydro's Energy Operations Planning Engineers and the experts involved in the Resource Planning and Production Scheduling communicate weekly on water supply and energy conditions.[146]

In reviewing the processes, Mr. Gawne explained that:

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[144] Transcript May 18, 2023, pages 983-984.
[145] Transcript May 17, 2023, pages 692-700.
[146] MH-30, MH Export, Drought Management and Hydrology Presentation, May 16, 2023, slide 6.

> *"water conditions and energy outlooks are regularly communicated to our senior leadership within Manitoba Hydro. And when conditions are extreme such as severe drought or -- or flooding conditions, our team will involve executive directly. For example, during the drought of 2021, we engaged the executive team of VPs and directors who met twice monthly throughout the drought to receive updates, to review our operating plans, and provide guidance on major decisions."* [147]

Greater detail is provided in Manitoba Hydro's Drought Management Planning Document.[148]

Mr. Gawne explained that staff are reporting on flows, reservoir levels, system potential energy and storage system potential energy inflows and precipitation to executive on "a monthly basis at minimum." [149]

Consistent with Manitoba Hydro's Drought Management Planning procedures, Mr. Gawne explained how regular communications on water and energy conditions were provided monthly, and "as conditions continued to be dry, the – the frequency of those communications was increasing."[150]

Daymark was provided with reports on water conditions, forward energy volume reports, and model outputs for the November 2020 through July 2022 period. Presentations delivered to the executive oversight team, and other reports and communications were also reviewed by Daymark. Daymark's findings confirmed that Manitoba Hydro appropriately followed its communication and executive engagement procedures:

> *"There will always be uncertainty as to the value of any particular action taken or avoided, especially from a position of hindsight. Nonetheless, we find that MH did comply with their written policies and procedures and took extraordinary care to continuously balance the often competing priorities that are part of operating such a large hydrological system. We further find that the RPPS and oversight meetings (and associated presentations) were*

[147] Transcript May 16, 2023, pages 552-553.
[148] MH-1, Application, Tab 5, Appendix 5.3, Section 7.1, page 27.
[149] Transcript May 16, 2023, page 608.
[150] Transcript May 17, 2023, page 715-716.

critical to ensuring that all priorities were met. The team of executive and senior leadership was formed to provide executive oversight during the drought." [151]

"MH did execute additional oversight and risk management consistent with its policies to ensure they maintained a safe and reliable system while accounting for competing operational and stakeholder priorities." [152]

In testimony, Daymark summarized how Manitoba Hydro followed its communications procedures, including informing executive:

"… operations was compliance with -- with policies and processes. They -- they clearly followed their processes. Their communications were very clear about their priorities. One (1) of the reasons we put those -- those six (6) com -- pieces of the -- of the Drought Management Plan in our report is that they -- they communicated that to their executive team. The -- the goal was for everyone to understand what constraints they were operating, what -- what were the policies, how did they approach it. There was clear indication of communication up and down the chain around those policies and the limitations and opportunities that they -- they placed upon them."[153]

8.4. Manitoba Hydro was Effective in Responding to the 2021 Drought and Managing Operations Through the Event

Manitoba Hydro provided an explanation of conditions leading up to the 2021 drought and its operations through spring and summer, 2021 starting at page 10 of its 2021 Interim Rate Application. An overview of conditions and Manitoba Hydro's response to the 2021 drought was also provide in Section 5.5.2 of the Application.

Drought is a complex phenomenon, particularly for a watershed as large and hydrologically diverse as the one in which Manitoba Hydro operates. Drought events are

[151] DEA-2, Daymark Independent Expert Consulting Report, April 13, 2023, pages 86-87.
[152] DEA-2, Daymark Independent Expert Consulting Report, April 13, 2023, page 9.
[153] Transcript May 18, 2023, page 986.

multi-faceted, and it is not as simple as Manitoba Hydro being “in drought” or “not in drought”. Mr. Gawne addressed this complexity during his explanation of how Manitoba Hydro’s Operating Priorities are applied as drought conditions develop and how Manitoba Hydro’s reservoir release decisions are made.[154]

Daymark made similar comments about the complexities of drought events:

> *“Drought is a word that’s convenient. It’s needed to have a conversation about a complex hydrological activity. But it is a complicated story. And it’s especially complicated when you’re talking about as large a watershed as you are for Manitoba. It – the watershed itself can, and frequently does, experience drought, flood, normal conditions sort of throughout its watershed. It’s not just in drought or not in drought.*
>
> *And to the extent that we can even talk about it in the simpler form of drought, its not in drought in the same place each time there is a drought. And so -- so where -- and as we discussed earlier, different parts of the system have a -- an outsized or a larger impact on energy production. So where drought is occurring has a material impact on Manitoba Hydro's ability to produce energy and -- and to dispatch their system reliably.*
>
> *It's also important to -- to recognize that drought is experienced by Manitobans far outside of just power generation. You can -- it can have agricultural impacts, it can impacts on transportation, fire prevention. It has environmental impacts. And it has quality of life impacts for -- for some of your citizens in terms of the use of the waterways and the access to water.”* [155]

Drought is also a creeping phenomenon. Unlike flood events, drought is not triggered by a single or sudden event that is easy to pinpoint. Instead, drought conditions evolve slowly over time, with an impact that gradually builds as dry conditions persist and future projections worsen. As a result, the exact onset of drought is seldom well-defined. As aptly summarized by Daymark:

[154] Transcript May 17, 2023, pages 692-700.
[155] Transcript May 18, 2023, pages 973-974.

> *"… drought comes in over time. It is not an instantaneous event. In the industry, it's frequently defined as a deficiency in precipitation over an extended period of time, usually a season or more, resulting in water storage [deficit]. It is a timed event. It occurs over time. So for life purposes, we can just think of it as weather conditions that worsen over time to cause duress on the system*." [156]

Considering these defining characteristics, Manitoba Hydro's drought risk continuously evolves as conditions in various portions of the watershed transition between wet and dry, and operations are planned and executed accordingly. Manitoba Hydro does not use a "critical drought threshold" to trigger a step-change in operations:

> *"I think we've heard Mr. Cormie explain this in the past, that a flag of there's a drought or there's no drought really is --is kind of difficult thing to -- to answer to. It's not like a switch is flipped and we're now in drought. So, yes, we are looking at conditions. And we were well aware that conditions were below average, and our planning accounted for that. But, as Daymark has confirmed with us I think to a question -- responding to a question by the Board where they characterized the use of our operating priorities, and those priorities I walked the Board through earlier today, is those priorities apply under all water conditions. And where we are in those priorities kind of may be driven by water conditions."* [157]

Daymark explained this in its report:

> *"In general, MH does not transition to any sort of alternative operations process upon water conditions deteriorating beyond a certain point. Rather, the Corporation's operational response to droughts should be thought of as an extension of normal operations wherein it pursues the objective of economic maximization within a set of constraints that are documented in their procedures and used daily. The challenges of operating the system change as system hydrology does, but the framework, which outlines the operational priorities and constraints under*

[156] Transcript May 18, 2023, pages 975-976.
[157] Transcript May 16, 2023, page 596.

which the teams operate, does not change, regardless of whether the system is flush, is in drought, or is anywhere in between."[158]

Leading up to April 2021, Manitoba Hydro was continuously monitoring conditions, updating inflow forecasts, and planning operations according to its pre-established priorities and procedures. Manitoba Hydro managed its system considering the dry conditions leading up to spring, while also looking ahead at the still uncertain summer flow conditions that had yet to transpire:

"… we're looking at this information every week. So, certainly as we see, you know, months and months of consecutive precipitation being below average, then, you know, we're -- we're alive to the water conditions all the time.

So, where we'd be coming concerned, we were projecting, you know, generation at the point -- once we got into March, April time frame, we were projecting a hydro generation for fiscal year '21/'22 to be below average, but we were also advising executive and others that there's still a lot of -- you know, there's the springtime. So, there was -- as I had said in the outset, March through August is when we typically get the most water in our system, so there was a lot of time left in the rain season to see the conditions recover. So, yes, we had -- storage conditions were about -- on April 1st, I think, overall storage conditions were about 80 percent of average and our flows I think were about 80 percent of average, and that was partially a product of -- of low snow melt runoff and the cumulation effect of a drier fall. So, we are aware of that, and we are -- we are planning accordingly with the understanding of our storage and -- and flows and the -- the state of the basin." [159]

In discussing whether Manitoba Hydro should not have released water in the spring of 2021 and instead stored more water sooner, Daymark commented:

[158] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 77.
[159] Transcript May 16, 2023, pages 594-595.

"MR. BOB PETERS: Did that energy have a greater value had it been left in storage?
MR. DOUGLAS SMITH: The -- the best models in that period -- so -- so when they – when they run their model, they are always using a value of storage as part of their calculus.

So I don't -- I don't mean -- I don't mean to be trite here, but -- but no because the model compared the -- the value of -- of selling versus the value of storage given all conditions: reservoir levels, conditions throughout their system, projections of future flows, as well as monitoring for the -- ensuring the maintenance of sufficient end of year -- end -- end of fiscal year storage to survive a drought in the following year.

So all of that is -- is occurring within the economic dispatch model, and the -- the value of the water that comes out is -- is what -- is what is planned for unless there are extenuating circumstances that come out of the [Resource Planning and Production Scheduling team]." [160]

In retaining Daymark as an independent expert consultant, the PUB specifically requested an assessment of Manitoba Hydro's drought operations through 2021 in the scope of work (Scope of Work #10).[161]

Daymark concluded that Manitoba Hydro's management throughout the 2021 Drought was both appropriate and effective, stating "[o]verall, MH managed its hydrology and energy forecasting, operations, and hedging effectively to adjust priorities as drought unfolded in 2021. MH followed its policies appropriately. We do not find any fundamental issues of note related to Scope items #10, #11 or #12."[162]

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[160] Transcript May 19, 2023, pages 1114-1115.
[161] DEA-2, Daymark Independent Consultant Expert Report, April 13, 2023, pages 94-97. (N.B. DEA's scope item numbering differs from Exhibit PUB-7, as explained on page 94 of DEA-2)
[162] DEA-2, Daymark Independent Consultant Expert Report, April 13, 2023, page 9.

8.5. Manitoba Hydro's Drought Operations Benefited from a Wealth of Expertise Across the Enterprise

While there appears to be concerns raised regarding the loss of experience or "relative dearth of experience of the senior Hydro management team,"[163] the evidence provided during the hearing shows that Manitoba Hydro is drawing from a *wealth* of expertise. As explained by Mr. Gawne, Manitoba Hydro has well established policies and procedures developed through decades of experience in previous drought operations that are used to guide its experts:

> *"Manitoba Hydro's reservoir and energy operations also -- I'll also refer to them as operations planning or that function -- uses long established priorities. These priorities are used -- pardon me, these priorities are used to guide a large team of experts from across the enterprise.*
>
> *And you'll see those listed here. I won't go through them in detail. But I'll note that this -- this team of professionals was referenced in Daymark's report as their Reservoir Planning and Production Scheduling Team…"* [164]

Many of these experts including staff in Energy Operations Planning, Wholesale Power Trading, and Enterprise Risk Management were involved in operating through the 2003/04 drought.

Mr. Turner explained how the Manitoba Hydro executive is involved during atypical or extreme conditions in providing oversight and guidance to the team:

> *" … the energy operations team and the experts, they all meet. And then, after that meeting, we'll get together that group of executives and they'll share with us, you know, their perspectives on potential actions or -- or things we should do to try and manage the risk.*
>
> *So the -- the executives are not in with all the experts while they're having those conversations. We're having a conversation after the fact where the*

[163] Transcript December 5, 2022, page 47.
[164] Transcript May 16, 2023, page 551.

experts have sort of aligned on some options, and then we'll provide our perspectives on -- you know, they may come to us with a recommendation: we think we should do some hedging or we think we should adjust our flow this way.

And then we have the right group of executives in the room to think about all those upstream and downstream implications of those decisions and share our perspectives." [165]

Over the period of Daymark's review of Manitoba Hydro, which included three days of face-to-face meetings, over 20 experienced and knowledgeable Manitoba Hydro staff participated in meetings with Daymark. The wealth of expertise was commented on a number of times during Daymark's testimony before the PUB:

"And they also use weekly team meetings. We'll discuss that in a – in a minute here, but they—they use a consensus building methodology to bring together various experts to – to ensure that this complex set of priorities is being managed." [166]

And:

"That it -- it might talk about some of the other stakeholder challenges or -- or concerns that -- that have come to mind and it -- and it walks through all this in -- at considerable detail and it's provided to this broad set of -- of experts within the organization. And those experts are identified in the -- in the drought planning the -- the -- the organizations within Manitoba Hydro are all identified within the drought planning document. And those experts come together and they build a consensus." [167]

And:

"I -- I think what we were -- what we were observing is that the process, as described to us, involved a ***great many experts*** *who reflect the various*

[165] Transcript May 17, 2023, pages 716-717.
[166] Transcript May 18, 2023, page 976.
[167] Transcript May 18, 2023, page 979.

positions of -- of the components of Manitoba Hydro and the stakeholders that they serve.”[168] [**emphasis added**]

Mr. Smith’s response was to a line of questioning related Daymark’s observation that *“*MH operations are extremely complex and much of the knowledge necessary to make appropriate trade-offs during adverse water conditions appears to reside in the minds of its **many** experts*.”*[169] [**emphasis added**]

Daymark commented further on the expertise in terms of recommending that Manitoba Hydro develop documentation of the expert knowledge:

“And so, the -- the point of this is that's always the case with an expert system, you can never capture everything that experts know structurally in documents or in -- but this might be an area in which additional investigation on the -- on the part of Manitoba Hydro to -- to look at that from a risk perspective and to see if there is more that they can do to mitigate potential risks around the -- the concept of -- of expert knowledge that does not exist memorialized in -- in documentation.”[170]

When asked if there was any impact to the apparent absence of documentation, Daymark explained there was no impact to Manitoba Hydro’s operations:

“MR. BOB PETERS: Did Daymark determine that the lack of written information or written directions cause any identifiable concerns during the 2021 drought management?

MR. DOUGLAS SMITH: No.

MR. BOB PETERS: There's no examples that you -- you can provide to this Board?

[168] Transcript May 19, 2023, page 1104.
[169] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 10.
[170] Transcript May 19, 2023, page 1105.

MR. DOUGLAS SMITH: No, the -- the -- in -- in -- in fact, it was clear that the expert knowledge was available to the RPPS team; that the breadth of -- of involvement in that team brought the necessary expertise to those weekly meetings.

The -- the point that we're -- we're making is that was -- that was possible because of the breadth of expertise that was in that virtual room, in that discussion, but not that there was a lack but that there could be a future concern, given the amount of that that resides in their experts and their expertise and their -- their experience." [171]

Manitoba Hydro appropriately involves its "great many experts" in its energy operations planning, and any lack of written information or written directions did not detrimentally affect its operations through the drought. Manitoba Hydro agrees with Daymark's summary and observations that "you can never capture everything that experts know" in documents. The very fact that "many" experts with decades of experience, some of whom were also involved in operations during the last major drought in 2003/04, are currently involved in operations mitigates exposure to loss of some key staff. However, Manitoba Hydro acknowledges and takes seriously Daymark's recommendation to develop more systematic documentation of this expert knowledge and Manitoba Hydro's processes. Manitoba Hydro will be augmenting its documentation on key processes and is embarking on a succession planning initiative to increase cross training in key functions; these initiatives will commence in the coming year.

9. MANITOBA HYDRO'S HEDGING PRACTICES DURING THE DROUGHT WERE REASONABLE

9.1. Manitoba Hydro's Hedging Activities in the 2021 Drought Were in the Best Interests of its Customers

During the drought of 2021, Manitoba Hydro's hedging activities were undertaken in the best interest of its customers. Hedging, especially during droughts, contributes to Manitoba Hydro's objective of having stable rates, especially given that drought risk, with its potential for significant negative financial impacts, has been identified as a top

[171] Transcript May 19, 2023, pages 1106-1107.

enterprise risk.[172] Through hedging, Manitoba Hydro seeks to shelter its customers from extreme energy price increases on purchases that could lead to significantly higher rates in the future.

As described in its response to PUB/MH I-18, during drought and while hedging in its day-to-day transactions, Manitoba Hydro is following a standard business practice and has proper policies, procedures, and approval authorities in place. In AMC/DEA I-12, Daymark was asked to comment on the appropriateness of hedging and if Daymark could provide examples. In its response, Daymark confirmed:

> *"Hedging trading risk is a standard process that most if not all utilities engage in. The extent and sophistication of the risk management policies and procedures surrounding hedging activity can vary widely and tend to correlate to the amount of hedging activity that occurs. For context, MH engages in less trading volume than many utilities that Daymark has reviewed or assisted in the past."* [173]

> *"… Beyond the utilities where we have played an active part in reviewing or shaping risk management policies we are generally aware that most electric utilities have hedging programs and policies…"* [174]

Further, Daymark stated that hedging was appropriate and removing the optionality of hedging would impose different types of risk and would not be advisable:

> *"Daymark believes that it is appropriate to allow choice when considering whether to (and to what extent to) hedge forward trading risk. Hedging, like any other form of insurance, incurs cost and professional judgement is required to ensure that facts and circumstances at the time of the potential hedge are considered in a final determination of whether to engage in a particular transaction. In general, removing the optionality of hedging (i.e.*

[172] MH-1, Application, Tab 3, Appendix 3.2, page 2.
[173] AMC/DEA I-12-a.
[174] AMC/DEA I-12-b.

forcing certain levels of hedging or prohibiting hedging) would impose different types of risk and would not be advisable."[175]

Mr. Gawne addressed Manitoba Hydro's operations planning processes and executive oversight, which includes oversight of Manitoba Hydro's hedging activities: "[…] during the drought of 2021, we engaged the executive team of VPs and directors who met twice monthly throughout the drought to receive updates, to review our operating plans, and provide guidance on major decisions."[176]

The existence of executive oversight was confirmed by Daymark when they reviewed MH's various policies and procedures:

> *"MH did execute additional oversight and risk management consistent with its policies to ensure they maintained a safe and reliable system while accounting for competing operational and stakeholder priorities."* [177]

9.2. Manitoba Hydro's Hedging Process is Systematic and Gradual

Manitoba Hydro follows a systematic and gradual approach for hedging. As explained by Ms. Sanclemente in her testimony, Manitoba Hydro does not take a view on the price in the market [redacted]. Recognizing there is price volatility in the electricity markets, Manitoba Hydro places [redacted] hedges over time [redacted] 4a. This gradual approach also has value in that there is significant uncertainty [redacted] due to unpredictable water supply conditions. Manitoba Hydro's process of gradually layering on the required hedges [redacted] 4a

This was explained by Ms. Sanclemente:

> *"..So what we do is we don't take a price view. we do two (2) things. We look at our hedges from a mechanistic perspective and a gradual*

[175] PUB/DEA I-14.
[176] Transcript May 16, 2023, pages 552-553.
[177] DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 9.

perspective. Mechanistic being we don't take a price view. We – we put positions on slowly over time. Gradual -- we want to do it gradually because we're not completely certain on what our water situation is going to be."[178]

Manitoba Hydro's mechanistic and gradual approach was confirmed by Daymark in the CSI session on May 19, 2023 as being appropriate and prudent:

[redacted] 4a

9.3. Manitoba Hydro Did Not Over Hedge in the Fall of 2021

Manitoba Hydro did not over hedge in the fall of 2021 [redacted] 4a Manitoba Hydro considered various factors when making its hedging decisions, including the potential for changing water conditions, and adjusted volumes accordingly. This was explained by Mr. Karanwal:

"….And that's the reason as we were going from August to September and October what we were seeing is how volatile the power sector could be in wintertime as we were getting it…. the whole spectrum, that was evolving month to month. And we were watching how the prices are evolving in the export markets. We were watching what was the situation of our water in the system. And that's the reason as these hedges were placed they were not rushed, but they were very thought through…." [180]

[redacted] 4a

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[178] Transcript May 17, 2023, page 729.

[179] [redacted] 4a

[180] Transcript May 17, 2023, page 728.

[redacted]

> [redacted] 4a

Daymark confirmed that the rationale and process for contracting hedges remained sound, despite the results:

> *"Hedges are used to mitigate risk and provide a measure of price certainty. While P197 states that the goal of wholesale power transactions is, in part, "to minimize the net costs to Manitoba customers," the emphasis is on reducing portfolio risk, not comparing the actual results of any given hedge. Given the potential for significant increases to the cost of procuring power over the winter, it was reasonable to hedge a portion of projected purchases in the fall of 2021 to protect against such a high-cost outcome."*[182]

[redacted] 4a

> [redacted] 4a

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181 [redacted] 4a

182 DEA-2, Daymark Independent Expert Consultant Report, April 13, 2023, page 92.

[redacted]

[redacted] 4a

[redacted]

[redacted] 4a

[redacted] 4a

9.4. Manitoba Hydro Will Consider Daymark's Recommendation on the Asymmetry of Risk in Purchases and Sales Transactions within its Hedging Strategies

Manitoba Hydro agrees with Daymark that there is an asymmetry of risk inherent in both purchase and sale transactions. As acknowledged by Ms. Sanclemente:

[redacted] 4a

[redacted]. 4a

[redacted]. 4a

[redacted] 4a

> *"*Manitoba Hydro acknowledges Daymark's recommendation. And there is work being led by the enterprise risk management division related to enterprise risk and tolerance, enterprise manage – or enter – excuse me – enterprise risk appetite and tolerance.
>
> *And we're working too from an energy trading perspective. And they're looking at shaping what the outcomes will be. So, we are definitely working on it, and we do take their – their point seriously."* [187]

Specifically, the work related to risk appetite and tolerance, being led by the Enterprise Risk Management division, will further shape and inform Manitoba Hydro's response to this specific issue and its overall efforts on managing and strengthening existing portfolio risk mitigation strategies

Until this work is complete, no final decisions have been made on potential strategy or policy revisions or any other potential portfolio risk metrics recommended for consideration.

10. ASSET MANAGEMENT & SYSTEM PLANNING

10.1. An Increase in Asset Sustainment Spending is Prudent Based on Asset Needs

Manitoba Hydro's assets are aging and system performance is declining. In Appendix 7.5 of the Application, Manitoba Hydro presented its Asset Management Sustainment Spending Projection Analysis, demonstrating that gradually increasing Business Operating Capital ("BOC") spending by approximately $200 million, over the next nine years, is /required to invest in aging assets that are declining in performance. This spending increase was calculated using a quantitative analysis aligned with good asset management practices.

Manitoba Hydro is confident, based on the results of this analysis, that this magnitude of increased spending is necessary and prudent. Progressive long-term planning aims to refine the projection as Manitoba Hydro's asset maturity grows. This will increase the accuracy of future capital requirements as the long-term capital plan is updated in the

[187] Transcript May 17, 2023, pages 811-812.

future. The $200 million estimate is conservative, as it does not account for the recent, higher-than-normal inflation,[188] and the analysis also excludes approximately 10% of asset classes. It is more likely the required increase in sustainment spending will be above $200 million as the spending need is further refined in the coming years, rather than lower.

10.2. Manitoba Hydro has Provided a Comprehensive Set of Asset Performance Measures that Clearly Justify an Increase in Asset Sustainment

Manitoba Hydro has provided a comprehensive set of asset performance measures across the Generation, Transmission, HVDC and Distribution operating areas that, when taken into consideration holistically, clearly justifies that an increase in asset sustainment is required. These measures, which are discussed in further detail below, include:

- Declining System Performance;
- Significantly Lagging Asset Intervention Rates; and
- Declining Planned Maintenance Completion Rates.

10.2.1. Declining System Performance

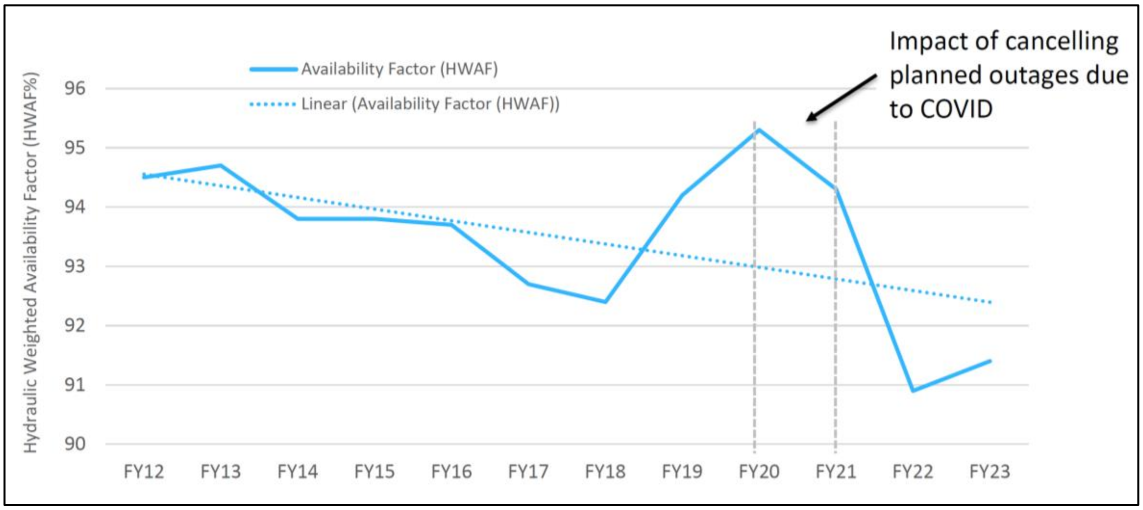
As noted in the Section 7.1 of the Application, Manitoba Hydro's system performance is declining. Specifically:

- Generation availability is declining;
- HVDC availability is declining;
- AC Transmission performance is declining; and,
- Customer outages and their duration are increasing.

These declines are depicted in the following figures. Notably, the 10-year trend of hydraulic average weighted availability and forced outage factors, shown in the figure below, demonstrates that overall, availability is declining and forced outages are increasing. This is attributed to assets reaching their end of life.

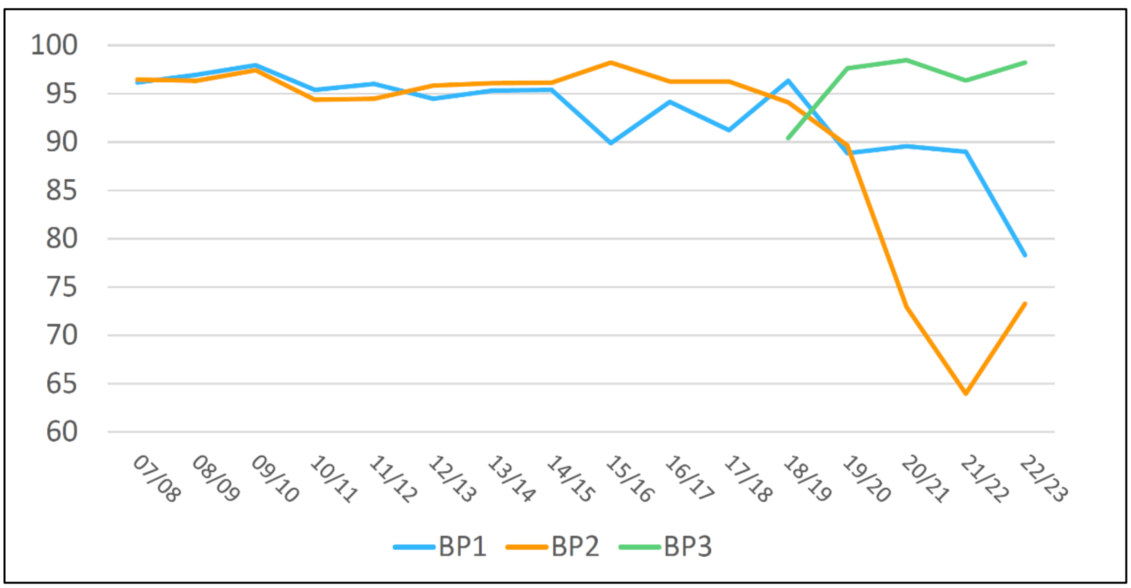
[188] MH-37, Statistic Canada Industrial Product Price Index; MH-38, Statistic Canada Machinery and Equipment Price Index.

Figure 13 - Trend of Hydraulic Weighted Availability[189]



The following figure depicts the trend over the last 16 years of Bipole availability. The availability of Bipole 1 and particularly Bipole 2, has declined in recent years.

Figure 14 - Bipole Availability[190]

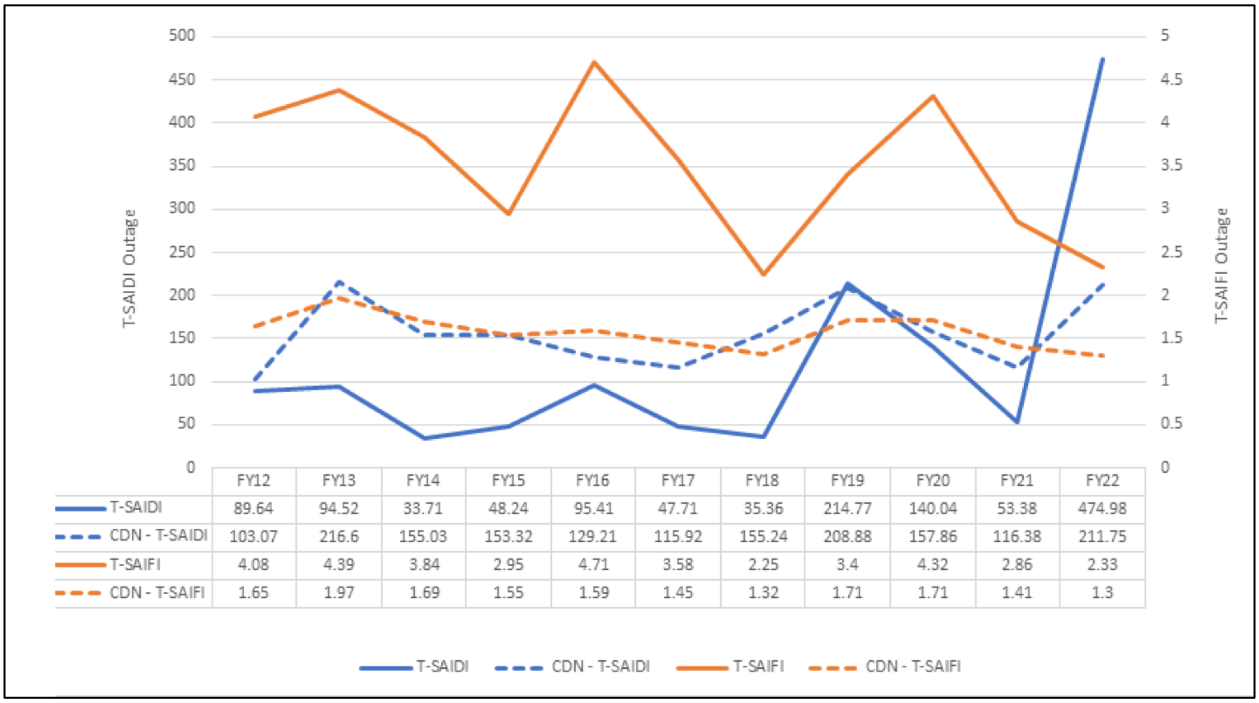


The Transmission System Average Interruption Duration Index ("T-SAIDI") and Transmission System Average Interruption Frequency Index ("T-SAIFI") are the primary metrics used to assess performance measuring the average duration and frequency, respectively, of interruptions on the transmission system. These metrics

[189] MH-33, Asset Management and Capital Panel Direct Evidence Presentation, May 23, 2023, slide 7.
[190] MH-33, Asset Management and Capital Panel Direct Evidence Presentation, May 23, 2023, slide 8.

are benchmarked against Canadian utilities and in both cases, Manitoba Hydro is showing current 10-year performance below the Canadian average, as demonstrated in the figure below.

Figure 15 - 10-year History of T-SAIDI and T-SAIFI Values[191]

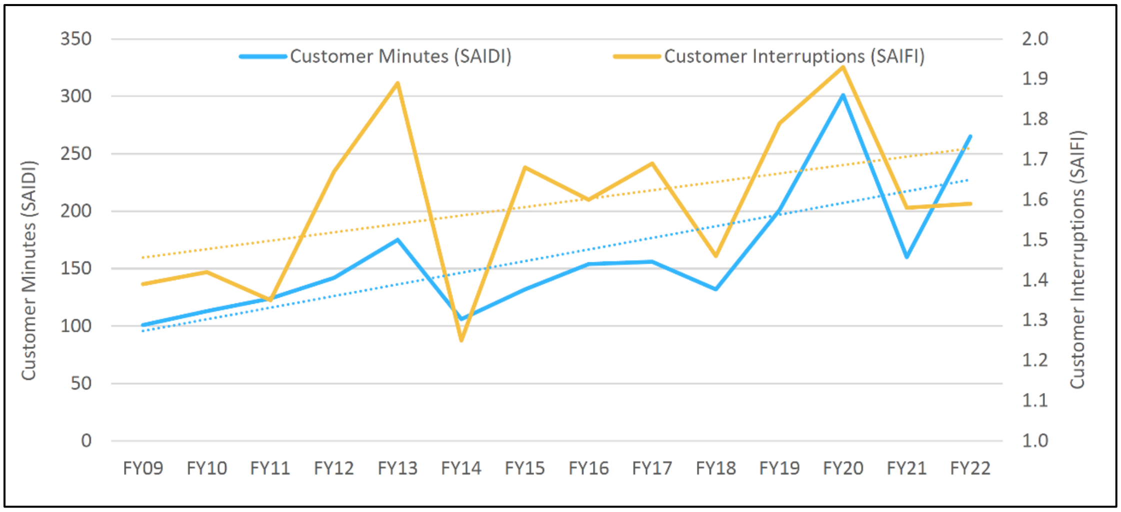


	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
T-SAIDI	89.64	94.52	33.71	48.24	95.41	47.71	35.36	214.77	140.04	53.38	474.98
CDN - T-SAIDI	103.07	216.6	155.03	153.32	129.21	115.92	155.24	208.88	157.86	116.38	211.75
T-SAIFI	4.08	4.39	3.84	2.95	4.71	3.58	2.25	3.4	4.32	2.86	2.33
CDN - T-SAIFI	1.65	1.97	1.69	1.55	1.59	1.45	1.32	1.71	1.71	1.41	1.3

The figure below shows SAIDI and SAIFI trends over the past 14 years, with a 5-year running average. Overall, an increase is shown. In terms of SAIFI, the increase in equipment failures is equivalent to approximately 5,000 additional customer interruptions every year and in terms of SAIDI, these customer interruptions have an equivalent duration of approximately 4 hours.

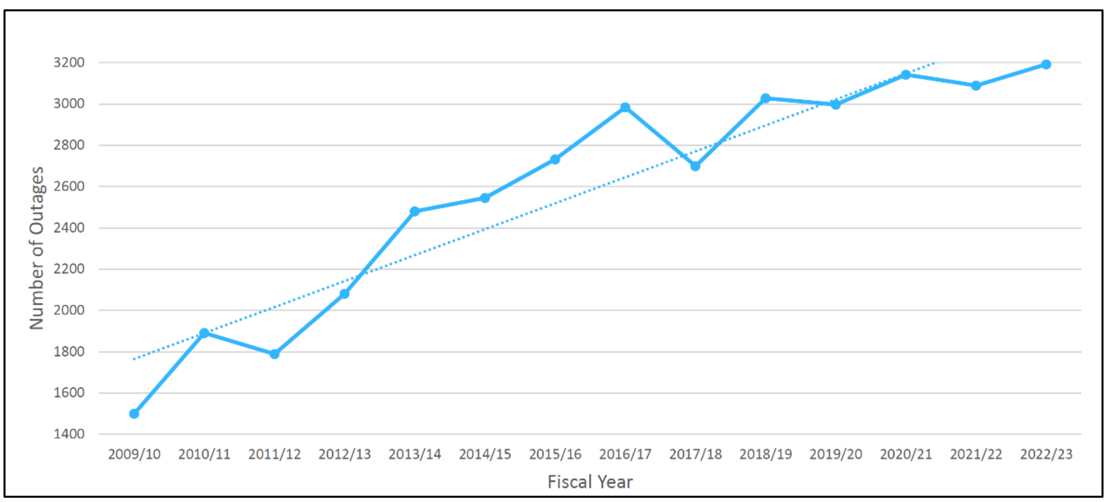
191 MH-1, Application Tab 7, Figure 7.4, page 11.

Figure 16 - Customer Reliability Trends[192]*10*



The next figure represents outages due to equipment failures over the past 14 years. The overall increase in SAIDI and SAIFI are, in part, driven by a significant increase in outages caused by equipment failure. It is important to note that all of these outages cause one or more customer interruptions.

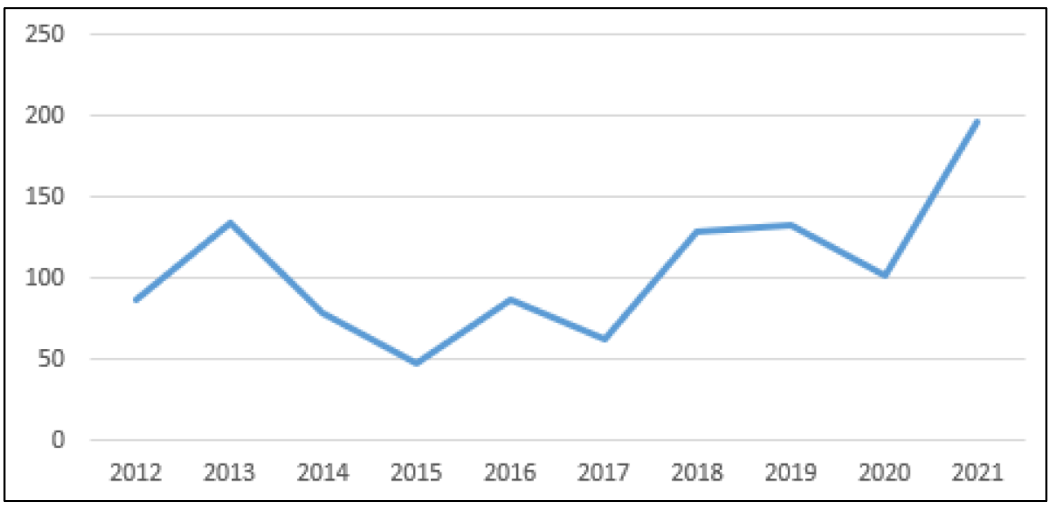
Figure 17 - Outages due to Equipment Failures[193]



[192] MH-33, Asset Management and Capital Direct Evidence Presentation, May 23, 2023, slide 10.
[193] MH-33, Asset Management and Capital Panel Direct Evidence Presentation, May 23, 2023, slide 9.

Manitoba Hydro's T-SAIFI has shown slight improvement in the last 10 years as depicted in the figure below. As weather is the dominant influence in this metric, equipment failure has been separated to analyze the impact of degrading assets. Despite the improvement in T-SAIFI overall, equipment failure is contributing negatively to the trend. Manitoba Hydro performance is historically unfavourable with respect to the Canadian T-SAIFI average due primarily to its transmission system design. The uniqueness stems from Manitoba Hydro's extensive use of radial 66kV transmission lines to economically serve Manitoba's extensive geographic distribution of small communities. As these radial 66kV lines are tapped off to supply several communities, an outage to one line will cause a disruption to many delivery points.

Figure 18 - Transmission System Delivery Point Interruptions due to Equipment Failure[194]



10.2.2. Significantly Lagging Asset Intervention Rates

Manitoba Hydro is projecting that many of its asset populations require significant increases in their rates of intervention. Monitoring and acting on asset type intervention cycles is considered a proactive approach to managing assets so as to control their effects on lagging system performance indicators (such as SAIDI/SAIFI, T-SAIDI/T-SAIFI, HVDC and Generation) in a stable manner. Deferring intervention on an already degrading system will result in poor performance and lack of resiliency under extreme weather events for many years after the time of investment.

[194] MH-1, Application Tab 7, Figure 7.5, page 12.

Manitoba Hydro's current asset intervention cycles for the majority of its major asset types are significantly lagging from their expected economic intervention rates (or run to failure rate for asset types where that strategy is appropriate) where the intervention rate represents an approach to minimize the total cost of asset ownership.

Manitoba Hydro projects that 16 asset types will need significant increases in intervention rates (i.e. >25%) by 2032. This evidence is presented in Appendix 7.5 of its Application and is summarized in the table below.

Figure 19 – Asset Intervention Rate

Asset Type	Current Intervention Rate[195]	Required Intervention Rate Error! Bookmark not defined. by 2032	Required Replacement Rate Error! Bookmark not defined. Increment	% Increase in Intervention Rate Error! Bookmark not defined. Required
Generators	1	2	1	100%
Hydraulic Turbines	1	1	0	0%
Exciters	1.8	3	1.2	67%
Governors	1.5	2	0.5	33%
Powerhouse Buildings	Varies (avg $4.6M)	Varies (avg. $7.6M)	0	N/A
Dams	Varies (avg. $8M)	Varies (avg. $21.7M)	0	N/A
Circuit Breakers	40	50.00	10	25%
Switchgear	2.6	4.00	1.4	54%
Battery Banks	38	42.30	4.3	11%

[195] Assets per year or km of linear asset per year.

Asset Type	Current Intervention Rate[195]	Required Intervention Rate Error! Bookmark not defined. by 2032	Required Replacement Rate Error! Bookmark not defined. Increment	% Increase in Intervention Rate Error! Bookmark not defined. Required
Station Power Transformers	22.00	25.00	3	14%
HVDC Converter Transformers	1.2	1.7	0.5	42%
Padmount Transformers	258	375	117	45%
Overhead Transformers	2130	2024	-106	-5%
Transmission System Steel Structures	70	230	160	229%
Transmission System Wood Pole Structures	70	264	194	277%
Transmission System Overhead Primary Conductor	35	151	116	331%
HVDC Converters	0	0.1	0.1	N/A – Infinite
HVDC Synchronous Condensers	0.45	0.45	0	0%
HVDC Electrode	0	0.1	0.1	N/A – Infinite

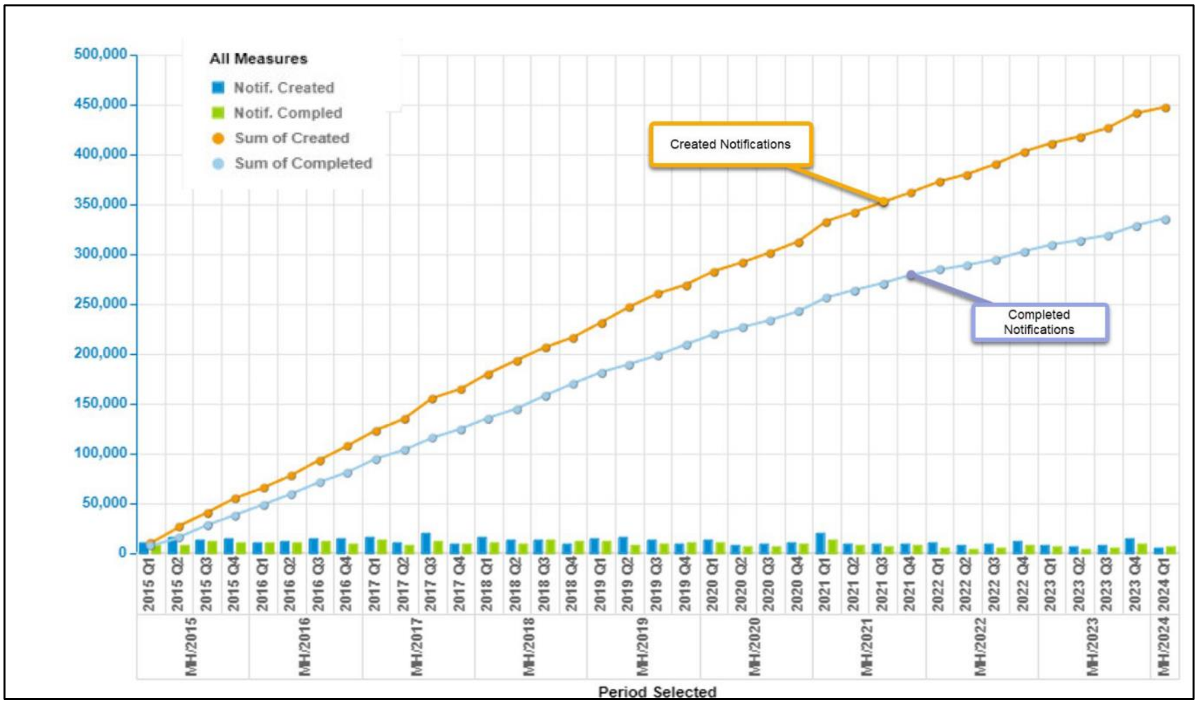
Asset Type	Current Intervention Rate[195]	Required Intervention RateError! Bookmark not defined. by 2032	Required Replacement RateError! Bookmark not defined. Increment	% Increase in Intervention RateError! Bookmark not defined. Required
Underground Cable	37	120	83	224%
Subsurface Utility Chambers	23	23	0	0%
Duct Lines	0.16	0.255	0.095	59%
Distribution Wood Poles	5000	11000	6000	120%
Distribution Overhead Primary Conductor	0	1150	1150	N/A – Infinite
Streetlight Standards	1350	1250	0	0%

10.2.3. Declining Planned Maintenance Performance

Asset failure rates typically increase as assets age and their condition deteriorates. As these asset failure rates increase, they exert a growing demand on maintenance and operations resources to respond accordingly. Through this growing reactive response, the time spent on preventative maintenance diminishes due to resource allocation.

Manitoba Hydro can only complete approximately 75% of planned (preventive) maintenance, which is expected to decline further without appropriate levels of asset renewal and trained maintenance resources. The figure below provides a visual example of the growing gap of created vs. completed reactive maintenance. The increased rate of asset failures and reactive work notifications on the distribution system requires increased asset interventions and additional operating and maintenance staff to stabilize and counteract this trend.

Figure 20 - Distributive Reactive Work – Created vs Completed[196]



10.3. Deferring Investment into the Future is Not Wise

Deferring required work may result in short-term gains of maintaining or lowering costs, however, it comes with serious long-term consequences. As stated by Ms. Halayko:

> *" …we have aging assets and we have investments that we have to make year after year. So any investment that we defer now is going to be for, you know, future Manitobans or for next year. It's not like the spending that we have now can be deferred and there's nothing following in its place. So risk is going up, reliability would be going down, and that -- that cost is just being pushed into the future. So we call that -- in asset management -- a bow wave that you're just pushing in front of you when you don't do things now."* [197]

When the performance decline is sudden or substantial and the number of deferred investments is too large to be executed simultaneously, a utility can face significant

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[196] MH-33, Asset Management & Capital Panel Direct Evidence Presentation, May 23, 2023, slide 11.
[197] Transcript May 23, 2023, pages 1138-1139.

challenges such as the inability to contain public safety risks to acceptable levels. Deferring investments and not adequately planning for the future would risk the sustainability of the electrical infrastructure for Manitobans. Ms. Vine warns of these risks, saying that she has been in a few organizations that, "have lost control of that balance… there's only so many people you can have doing repairs at the same time without taking, you know, safety and availability risks."[198]

Manitoba Hydro determines optimum economic life based on a variety of values held in the Corporate Value Framework ("CVF"). Customer outages, safety incidents, environmental impacts, and lost revenue, are some significant examples of risks of deferring investment. Deferring asset investments beyond the most economic point results in these risks growing. If risk is allowed to grow across large asset populations, some of these risks will materialize. As these risks materialize, they can impact the larger Manitoba Hydro systems.

While Manitoba Hydro is committed to maturing its asset management system and increasing the accuracy of its long-term planning, the evidence provided is appropriate and sufficient to conclude that a bow wave is beginning to form and increasing the level of investment in assets is economic, responsible and necessary. As long-term planning accuracy increases with each release of Manitoba Hydro's Asset Management Plan, the trajectory of the increased spending will be refined. It is certain that asset spending needs to increase based on an aging asset population. Delaying a response to this certainty will introduce risks on customers, both current and future.

Midgard further supports its recommendation to reduce BOC spending by at least 10% by citing three projects to defer. The consequences of deferring those three investments are unfavorable to both Manitoba Hydro and its customers, as summarized below:

- <u>Grand Rapids Unit 4 Overhaul:</u>[199]
    - Grand Rapids Unit 4 provides 125MW of renewable energy, has flexible energy storage used for meeting winter dependable energy needs, is a key source of automatic generation control for Manitoba Hydro, and functions as a synchronous condenser to provide voltage support even when not generating

[198] Transcript May 23, 2023, page 1309.
[199] CC/MH I-122a-m, Attachment 1, page 35.

active power.

- The positive value produced by this project is approximately ten times the cost of $18.6 million.
- The payback period is less than one year, hence the high Lost Generation Risk score in the Corporate Value Framework.[200]
- Reactive replacement on generating unit failure can result in up to three times the lost generation cost to Manitoba Hydro and its customers versus proactive replacement.

- Pointe du Bois Renewable Energy Project (PREP):[201]
  - Without PREP the need date for new resources for additional capacity is 2029/2030 based on persistent capacity deficits. [202]
  - With PREP the need for new resources for additional capacity is moved to 2030/2031 based on persistent capacity deficits.[203]
  - If not completed, other resources would be required.
  - PREP compares favorably with wind and solar generation resources from a cost perspective and is dispatchable which provides more value for meeting peak load.
  - Deferral may limit Manitoba Hydro from pursuing the $114 million of federal funding in its entirety which requires completion by 2027/2028.

- Bipole I & II Refurbishments:[204]
  - Bipole failure poses a safety risk to Manitoba Hydro staff and its customers.
  - A sustained failure of any Bipole will result in substantial reliability and financial impacts to Manitoba Hydro and its customers including the requirement to import power at a significant cost, and increased likelihood of customer outages during the winter.
  - Equipment failures and obsolescence will lead to certain Bipole failure and restoration times would be several years.
  - If both Bipole I and II modernization are deferred, the risk grows to an

[200] CC/MH I-122a-m, Attachment 1, page 40.
[201] MIPUG/MH I-82d, Attachment 1, page 17.
[202] Coalition/MH II-103a, page 2.
[203] MFR 43, Figure 1 Winter Peak Capacity Supply & Demand Table.
[204] MH-1, Application Tab 7, Appendix 7.7, page 10.

inevitability that both Bipoles will be on prolonged outage simultaneously.

Pursuing increased spending to address aging assets and mitigate performance decline is imperative to ensure reliable and affordable electricity for Manitobans into the future. The fact that assets degrade as they age and need to be replaced cannot be disputed. Manitoba Hydro utilizes appropriate, quantitative techniques to predict future asset needs, and condition and value-based decisions to determine the optimal portfolio of investments. The plan presented by Manitoba Hydro is in the best interest of Manitobans.

10.4. Manitoba Hydro has Clearly Demonstrated a Strong Commitment to Advancing its Asset Management Maturity

Manitoba Hydro is making good progress in advancing its asset management maturity and has taken significant steps in this direction. This was confirmed by an international expert in asset management ("AMCL"), who was retained to perform the 2022 maturity assessment. The scope of the maturity assessment was very comprehensive, including a range of criteria and 293 questions. This level of detail was by design, so that the findings could be used to inform future actions. Manitoba Hydro is currently implementing the recommendations of the 2022 maturity assessment.

Further demonstrating its commitment to advancing its asset management maturity, Manitoba Hydro developed a formal Asset Management Policy and its first Strategic Asset Management Plan ("SAMP"),[205] one that is upheld as a strong example in the industry. The 2022 AMCL maturity assessment noted that the objectives outlined in Manitoba Hydro's SAMP remain appropriate. Since the issue of the maturity assessment, Manitoba Hydro has made progress on delivering those objectives, such as issuing its first Asset Information Strategy[206] in early 2023. Manitoba Hydro has also developed its internal competency, providing 450 staff with formal asset management training.

A significant reorganization was undertaken around an asset management functional model. Harmonizing the asset management functions through reorganization allows consistency, avoids duplication of efforts, and allows building of a single centre of expertise within the company. Previously, maturity progression was limited with separate

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[205] MH-1, Application Tab 7, Appendix 7.2.
[206] MH-47, Attachment 1 to Undertaking Accepted at Transcript Page 1516.

asset management groups embedded within the operating units (transmission, distribution, generation). This restructuring initially slowed progress in maturity while functions were being harmonized, but it has laid the foundation for significant future progress. In its 2022 Maturity Assessment report, AMCL confirmed, "[t]his restructuring positions Manitoba Hydro to further improve its asset management maturity…" [207]

It is important to note that the maturity assessment focused on the asset management system's coordination, integration, and standardization. Manitoba Hydro's former organizational structure of separate operating units gave rise to variation in what should be shared practice. At the time of the assessment, restructuring to a centralized asset management group was new and aligning best practices across the operating units was in the early stages of development. This contributed to lower scores in the 2022 assessment.

Maturity assessment results have been mischaracterized by Midgard, citing that the lowest scores result in the inability to make any decisions.[208] The maturity of Manitoba Hydro's asset management system was assessed, not the credibility of its asset management decisions. Asset management system maturity refers to the existence and sophistication of standardized practices and process as opposed to the effectiveness of decisions. Manitoba Hydro is practicing asset management and the decisions it has historically made have resulted in very good performance and reliability. Asset management maturity is a continuum. Manitoba Hydro is seeking to continuously improve and has credible plans to do so.

Manitoba Hydro's asset management maturity was cited as a reason to question asset investments. It was suggested that the inability to precisely quantify and map the impacts of investments or rate increases to performance is an indication of an ineffective asset management system.[209] As stated below, decisions are made based on quantification of investment value via the CVF. Mapping of cost directly to performance is only possible at an extremely high level of maturity, that few companies can or would want to achieve, given the costs and resources required. As stated by Ms. Vine: "that's reminiscent of the

[207] MH-1, Application Tab 7, Appendix 7.4, AMCL Report, page 3.
[208] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporation, April 3, 2023, pages 60-61.
[209] Transcript May 24, 2023, pages 1591-1593.

level of maturity in the UK where they've been doing performance based regulation for twenty (20) years […] it's hard work and very difficult to demonstrate that link directly between your investment and your level of performance."[210]

In many ways, Manitoba Hydro had previously been operating with different systems for managing assets (generation, transmission and HVDC, electric distribution). Maturing the asset management system involves not only advancing the practices, but also harmonizing the practices of each of these areas. As noted by Ms. Vine, the speed of maturity advancement varies by the size and complexity of the organization. She noted that, "the smaller the organization, the easier it is to make systemic change"[211] and compared this type of change in a small organization like steering a speedboat, versus steering a shipping container with an organization the size of Manitoba Hydro.[212] Ms. Vine noted that the size of Manitoba Hydro makes it harder and slower to move up the asset management maturity scale.[213]

The pace at which Manitoba Hydro is advancing appears to be on par with North American utilities that are strategically advancing asset management. For example, Ms. Vine confirmed that it has taken B.C. Hydro about the same amount of time to advance its asset management maturity.[214] Manitoba Hydro is ahead of other utilities that are apart of CEATI in certain areas of asset management. For example, Manitoba Hydro is regularly asked to share how it successfully implemented the Corporate Value Framework.[215]

10.5. Our Asset Investment and Portfolio Planning is Robust

Manitoba Hydro has robust asset investment and portfolio planning processes and has matured beyond simple prioritization of work. Using the established CVF and the Copperleaf planning tool, Manitoba Hydro is optimizing its investment portfolios.

A priority listing is nothing more than a ranking, using a fixed score based on a single metric. The Enwin investment portfolio example provided by Midgard as an approach that

[210] Transcript May 24, 2023, page 1446.
[211] Transcript May 23, 2023, pages 1293-1294.
[212] Transcript May 23, 2023, page 1291.
[213] Transcript May 23, 2023, page 1291.
[214] Transcript May 23, 2023, page 1295.
[215] Transcript May 24, 2023, pages 1460-1462.

creates an opportunity for robust and transparent testing of capital plans[216] is an example of a list of investments that have been prioritized by value and capped at a fiscal target.

Portfolio optimization improves the short-term planning methodology such that higher value outcomes can be achieved while honouring multiple constraints. Optimization is a much more advanced method of portfolio planning and as detailed in Tab 7 of the Application, Manitoba Hydro optimizes the portfolio of investments within Copperleaf using an iterative approach to ensure all constraints, including financial targets, resource availability to execute work, and outage constraints, are respected.

Even though Manitoba Hydro's investments are optimized within separate portfolios, all investments are valued using the same framework, applied by a centralized valuation team to ensure consistent application of the CVF. This is opposed to Midgard's claim that Manitoba Hydro is not sophisticated enough to do cross-functional prioritization of projects.[217] Further, in the AMCL report, Ms. Vine stated:

> *"Manitoba Hydro's CVF is in place and used for capital decision-making throughout the organization from generation through to distribution and for non-energy assets such as fleet and facilities. Applying the same CVF across generation, transmission, distribution, and non-energy assets is challenging and not yet common practice in North America*."[218]

Significant analysis and consideration is given when determining the allocation of financial targets between the Generation, Transmission and Distribution portfolios. This analysis accounts for committed spend (i.e. projects that Manitoba Hydro is actively executing), and current/future asset needs based on age and/or condition when appropriate. This approach is contrary to Midgard's assertion:

> *"Presumably the overall capital spending targets are therefore determined in discussions between the senior management team, the MHEB and the Government. How the overall capital envelope is then allocated between*

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[216] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, pages 44-48; Transcript, May 25, 2023, page 1712.
[217] Transcript May 25, 2023, page 1777.
[218] MH-1, Application Tab 7, Appendix 7.6, AMCL Report, page 1.

projects in the Generation, Transmission & Distribution business groups is not clarified in evidence, but the implication is that the group that lobbies most effectively for its cause will be allocated the biggest envelope." [219]

As stated in Manitoba Hydro's Application and reiterated during the hearing, short-term investment decisions, including allocation of Business Operations Capital funds, is on a needs-basis entirely driven by asset conditions and prioritized through the CVF.[220]

Midgard stated it never got a prioritized list showing the value stream and the point at which the marginal project was cut off.[221] The Capital Expenditure Plan provided in Appendix 7.7 is an optimized listing of investments as it is populated from the results of portfolio optimization. There is no "marginal cutoff" CVF value for investments because the Copperleaf software calculates the maximum portfolio value (the portfolio being the grouping of capital investments) over the optimization period (typically 5-7 years for short-term planning).

The approval documents and CVF are analogous to a business case assessment and represent the supporting documentation for capital investments.[222] Numerous business case examples have been provided through the information request process[223] which is contrary to multiple claims by Midgard that Manitoba Hydro has not provided any:

"MR. CHRISTOPHER OAKLEY: I want to see a business case … show me the MPV [sic] with the risk -- risk adjusted returns and the cost of this over the period."[224]

"MR. CHRISTOPHER OAKLEY: If I could see a really clear business case around, for example, Grand Rapids 4, I could tell you, well, what's -- what's its job and is it making a return on that. If it's critical to reliability, then let's see that evidence." [225]

[219] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 43.
[220] Transcript May 29, 2023, pages 2010-2011, 2140-2141, and 2146-2147.
[221] Transcript May 25, 2023, page 1705.
[222] Coalition/MH II-118.
[223] Coalition/MH I-122 and MIPUG/MH I-82.
[224] Transcript May 25, 2023, page 1708.
[225] Transcript May 25, 2023, page 1851.

Each investment in Appendix 7.7 has already progressed through a portion of the gated approval process,[226] depending on whether the investment is moving in scope development or execution. At each gate, the Capital Investment Concept ("CIC") or Capital Investment ("CIJ"), and the CVF valuation, are reviewed by the appropriate level of management or executive, commensurate to the cost of the investment and following corporate policy. The assessment of risk and/or benefit that makes up the valuation is done by Manitoba Hydro's skilled staff, many of whom are recognized experts in their fields.

Manitoba Hydro ultimately concurs with Mr. Helland's comments that the best party to decide what role the asset should play in the system and how best to use those assets is Manitoba Hydro,[227] and that Manitoba Hydro, in accordance with its governance structures and meeting its legislative obligations as a Crown owned utility, is the best situated entity to quantify how much it should spend on operation staff compared to capital expenditures to reduce outage duration.[228]

10.6. Manitoba Hydro's Use of Asset Condition in Short-term Planning/Decision Making

As any particular asset transitions from the long-term planning horizon (5 years or more) into the short-term planning horizon (5 years or less), Manitoba Hydro uses condition, not age, as an input into CVF evaluation to quantify risk as part of short-term capital investment decision-making. This is clearly noted at Tab 7, page 27 of the Application and is reflected in the various capital investment CVF evaluation scores presented within Manitoba Hydro's evidence.

Manitoba Hydro uses specific condition measures (measures that are typically used as Asset Health Indices inputs), as appropriate, as part of its decision making.

As part of the newly reorganized Asset Management Division, Manitoba Hydro is working towards harmonizing and creating a sustainable set of Enterprise Asset Health Indices to create a more refined long-term planning view of its asset sustainment needs. In the

[226] MH-1, Application Tab 7, Figure 7.14, page 41.
[227] Transcript May 25, 2023, page 1791.
[228] Transcript May 25, 2023, page 1897.

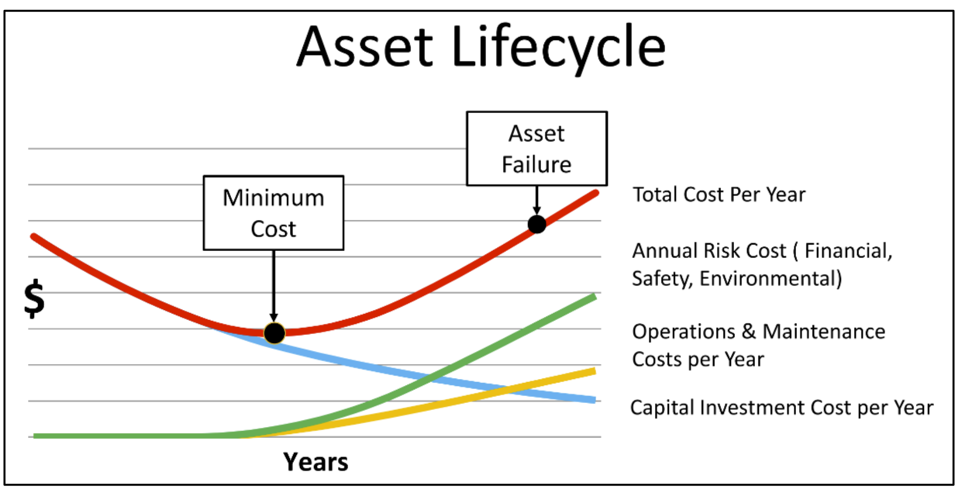
interim, asset age demographics are used to forecast the needs of an entire asset population for long-term planning purposes, which is an appropriate way to approach long-term planning as noted by Ms. Halayko:

> *"[…] age provides us with an estimate accurate enough for this long-term plan. Variances in the observed asset life that are shorter or longer than the economic life for an individual asset will balance out amongst this large population."* [229]

10.7. Asset Class Strategies are Validated Using Whole Life Cost Models & Available Data

One aspect of Manitoba Hydro's long-term planning process includes evaluation of specific critical asset class strategies and the development of Whole-Life Cost models. A simple illustration of this model is depicted below:[230]

Figure 21



Whole-Life Cost models discussed in Tab 7, section 7.2.6.2 of the Application are used as inputs into Manitoba Hydro's Asset Class Strategies and have been implemented over recent years in its asset management journey. Whole-Life Cost models demonstrate a standardized, repeatable, and transparent process which consider the growing maintenance costs and risks associated with an aging asset and provides information on

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[229] Transcript May 23, 2023, page 1179.
[230] MH-33, Asset Management & Capital Panel Direct Evidence Presentation, May 23, 2023, slide 17.

the lowest economic lifecycle cost of the asset. Manitoba Hydro does not focus only on the declining average annual replacement cost. It makes informed, value-based decisions for investment and asset renewal strategies through the entire lifecycle of the asset. This information validates that replacement is optimal and identifies the recommended optimal lifecycle when options exist.

Looking out 20 years and beyond allows Manitoba Hydro to determine funding requirements and need for skilled resources which can be quantified through tools such as the Whole-Life Cost model. As a specific asset investment moves closer to the short-term horizon, a more detailed analysis is done, including a review of the condition of that specific asset and scoping exercise to be included within the project.

Manitoba Hydro incorporates several variations of asset class strategies that depend on the asset class. Asset strategies include reactive, run-to-fail, as well as the combined condition/age-based intervention strategy. Midgard's evidence is that the level of data quality issues prevent Manitoba Hydro from planning and executing sustainment activities within its Asset Class Strategy, however Manitoba Hydro has specifically provided examples in Appendix 7.5 of the Application that include programs such as the integrated pole maintenance program ("IPM") to incorporate evidence-based condition data, combined with age to prioritize strategic asset intervention on wood poles.

10.8. AMCL is Independent and Rebuttal Evidence Should be Considered

Manitoba Hydro presumes that the Consumers Coalition will argue that Appendix 2 to the May 5, 2023 Rebuttal Evidence of Manitoba Hydro ("Appendix 2"), which was authored by Ms. Sarah Vine of AMCL, should be afforded no weight based on the submission in Mr. Klassen's letter dated May 19, 2023.[231]

Manitoba Hydro agrees that the principles articulated by the Supreme Court of Canada in *White Burgess Langille Inman v Abbott and Haliburton Co.*[232] are instructive to this Board for determining whether an expert has met its duty of independence, impartiality and absence of bias.[233] In particular, the Supreme Court held that there are two steps for

[231] CC-22, Letter to PUB re Rebuttal Evidence by AMCL.
[232] 2015 SCC 23 [*White Burgess*].
[233] *White Burgess,* paragraph 32.

determining admissibility of expert evidence.

At the first stage, the proponent of the evidence must establish the threshold requirements of admissibly based on relevance, necessity, absence of an exclusionary rule and a properly qualified expert.[234]

The second step is described as a “discretionary gatekeeping step” where the decision maker balances the potential risks and benefits of admitting the evidence in order to decide whether the potential benefits justify the risks. This determination involves taking concerns about the expert's independence and impartiality into account.[235]

Manitoba Hydro understands that the Consumers Coalition takes no issue with the first stage threshold requirements relating to the expertise or admissibility of Ms. Vine’s limited commentary on Midgard’s assertions and recommendations with respect to Manitoba Hydro’s asset management journey, with which Ms. Vine is intimately familiar given AMCL’s specific consulting services in this respect. Rather, it appears that the Consumers Coalition’s specific concern with Appendix 2 is that AMCL “contests multiple of Midgard’s assertions and recommendations” while making only one reference to its prior evidence. The logically flawed conclusion of the Consumers Coalition is that AMCL (and Ms. Vine, as its representative) assumed the role of advocate for Manitoba Hydro, as opposed to being independent, objective and non-partisan, and therefore the limited observations of AMCL on Midgard’s evidence should be afforded no weight by the PUB.

Manitoba Hydro strongly disagrees with the Consumers Coalition that no weight should be given to Appendix 2 and all of the evidence presented by AMCL and Ms. Vine on its behalf. First, it is clear that Ms. Vine, on behalf of AMCL, is an independent, impartial and unbiased expert witness on Asset Management matters. In addition to the credentials of AMCL and Ms. Vine, further illustration of this independence is observed during cross-examination by PUB’s legal counsel, where Ms. Vine confirmed that she was prepared to be critical of Manitoba Hydro when responding to his questions,[236] and, in fact, AMCL and Ms. Vine was critical of aspects of Manitoba Hydro’s asset management. Clearly, AMCL and Ms. Vine carried out the duty of an expert to be independent, impartial and non-

[234] *White Burgess,* paragraph 23.
[235] *White Burgess,* paragraphs 24, 54.
[236] Transcript May 23, 2013, page 1286.

partisan.

Throughout AMCL's reports and during Ms. Vine's testimony, the evidence has been entirely reliable and credible attempting to assist the PUB in its decision-making role by having the most accurate information before it. Manitoba Hydro strongly disagrees that AMCL was "vociferously" defensive of Manitoba Hydro as alleged and notes legal counsel for the Consumers Coalition did not challenge the analysis of AMCL contained in Appendix 2 during cross-examination of Ms. Vine.

Offering reasonable, informed, objective and respectful independent commentary in direct response to Midgard's comments and recommendations contained within its evidence to assist the PUB does not equate to the purported conclusion by the Consumers Coalition that AMCL assumed a role as an advocate for Manitoba Hydro or that it is non-partisan. Rather, AMCL simply offered informed and limited commentary and observations on a flawed report authored by Midgard for the PUB to consider.

The catalyst for Manitoba Hydro retaining AMCL was based on the PUB's directive to retain an independent consultant to update and assess the recommendations that had been made by UMS Group Inc.[237] Ms. Vine has over 30 years of global experience in asset management and is well-positioned to provide an independent, impartial and un-biased summary of that assessment to the PUB. Manitoba Hydro submits that all of the work that was completed by AMCL to fulfill the directive provided by the PUB, including Appendix 2, only serves to further assist the PUB in providing an independent assessment and understanding the progress and opportunities of Manitoba Hydro's asset management, unlike the representatives of Midgard who are routinely engaged to provide consulting services and evidence on behalf of consumer groups, such as the Consumers Coalition, before utility regulators.

11. MIDGARD'S EVIDENCE IS DEEPLY FLAWED AND UNRELIABLE

Midgard subjectively recommends a reduction in BOC of "at least" 10%.[238] This vague and arbitrary recommendation of an "at least 10" reduction stands in contrast to the objective and quantitative future spending increase projected by Manitoba Hydro in Appendix 7.5

[237] PUB Order No. 59/18, Directive 14.
[238] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 85.

and the investment portfolio in the Capital Expenditure Plan presented in Appendix 7.7. Midgard does not offer any evidence to counter the conclusion that a $200 million increase in sustainment spending is required, but instead agrees with the results of Manitoba Hydro's projection in Appendix 7.5, acknowledging that the current planned replacement rates for some asset types are expected to be inadequate over the longer term.[239] Midgard questions the timing of the investments; however, they have not provided any evidence to demonstrate that Manitoba Hydro's recommendation to ramp up asset intervention rates over the next ten years is premature.

In its critique of the analysis in Appendix 7.5, Midgard has suggested, on numerous occasions, the benefits of reactive "run-to-fail" strategies over proactive replacement strategies, implying run-to fail strategies are not used by Manitoba Hydro. This is not true. The example of "pole top" or overhead transformers was referred to several times during Midgard's oral evidence.[240] Manitoba Hydro has clearly indicated that that it already employs a run-to-fail strategy for this asset class.[241] Midgard has not provided any evidence to show where Manitoba Hydro should use reactive strategies beyond where they are already used. It is worth noting that Midgard has generally stated that rather than proactively replacing assets, Manitoba Hydro should let assets fail and customers could proactively prepare for outages due to the asset failures with fossil fuel backup generation.[242] Manitoba Hydro's approach for proactive, value-based asset replacements are based in good asset management, as stated by Mr. Pawluk:

> *"For the majority of our assets, it is most effective to replace or refurbish them proactively versus operating them until they fail. Proactive replacement minimizes outage costs, impacts the customers, and the risk of increase cost and safety environmental impacts due to collateral damage from a failure."* [243]

Midgard failed to consider the financial costs, environmental risks, safety risks, legal compliance, and lead times associated with deferring investment when making its

[239] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 73.
[240] Transcript May 25, 2023, pages 1675, 1697, 1718, 1834, 1886, 1888, and 1895.
[241] MH-1, Application, Tab 7, Appendix 7.5, Section 1.13.1; CC/MH II-98e.
[242] Transcript May 25, 2023, pages 1666, 1670, 1860, and 1861.
[243] Transcript May 23, 2023, page 1155.

recommendation to the PUB that Manitoba Hydro should reduce its BOC spending by "at least 10%." Clearly, the recommendation is arbitrary and without any merit and incorrectly assumes that the PUB has the requisite jurisdiction to provide such a directive to Manitoba Hydro in its resultant order with respect to the Application.

Manitoba Hydro submits that Midgard has a fundamental misunderstanding of Manitoba Hydro's system, as demonstrated by its focus on the wrong system performance metrics, misunderstanding of market interactions, misunderstanding of impact of generation outages. These points, among others, are detailed in the following sections.

As a result of these misunderstandings and flawed conclusion, Manitoba Hydro submits that no weight, or alternatively very little weight, should be afforded to Midgard's evidence.

11.1. Midgard Focuses on the Wrong System Performance Metrics

Manitoba Hydro strongly disagrees with the assertion by Midgard that distribution performance metrics should be used to justify reducing investments in Generation, Transmission and HVDC assets. Manitoba Hydro provided a comprehensive set of asset performance measures across all operating units that Midgard could have taken into consideration as part of its evaluation.

Midgard claims that Manitoba Hydro focuses on the asset and ignores the system when it was confirmed that a generator outage does not normally result in an interruption of service to customers (i.e. SAIDI/SAIFI).[244] From this connection, it is apparent that Midgard focuses on the wrong system performance metrics when attempting to justify permitting generation assets to degrade further.

Generation within Manitoba Hydro's electric energy system acts as a pool of energy that is dynamically and continually being adjusted over varying seasonal loading demands and water conditions. It acts to serve both domestic needs and export commitments as well as support the stability and reliability of the larger power system. It is more appropriate for generation assets' performance to be evaluated as a system, as per their overall

[244] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 51.

availability within the electric system to meet the capacity and energy requirements. As outlined by Mr. Gawne:

> *"So given that we're predominately hydroelectric system, our system is planned and built to reliably supply our customers under drought. And as -- as I said, when we're not in drought, we usually have surplus energy which is why we are typically exporting energy to our neighbours, and this is why we need to look at it from a system approach when we're forecasting our net export revenues."* [245]

Application of distribution performance metrics to justify further reduction of asset sustainment in the generation system is confirmed to be inappropriate by Ms. Vine:

> *"If the generation system performance were impacting outages for domestic customers, it would indicate a total failure to manage the system. […] The distribution system predominately drives SAIDI/SAIFI performance. Reducing investment in asset sustainment of the generation system until it deteriorates to such an extent that it impacts SAIDI/SAIFI performance would significantly increase the capital cost risk to future customers; these customers would also be facing prolonged periods of degraded performance as the investment backlog is being addressed."* [246]

Midgard ignores generation availability performance metrics and incorrectly use distribution system performance metrics to advocate that generation assets should be allowed to degrade further.[247] Midgard advocates for generation assets to degrade to such a point that there is a total failure to manage the electrical system. Clearly, this would result in significant financial loss (i.e. loss of export revenue and purchase of import power) and subject Manitobans to significant domestic service impacts (i.e. prolonged blackouts). Only at that juncture, by Midgard's opinion, is action warranted which may take years to address as refurbishing and adding new generation takes years from planning to completion. Manitoba Hydro strongly disagrees with that approach as the associated risks would be detrimental to Manitobans.

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[245] Transcript May 16, 2023, page 548; MH-30, MH Export, Drought Management and Hydrology Presentation, May 16, 2023, slide 27.

[246] MH-24, MH Rebuttal Evidence, Appendix 2, page 155.

[247] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 51.

11.2. Midgard Does Not Understand Manitoba Hydro's System or Its Market Interactions

The export market is key to Manitoba Hydro's economic and reliable operations, providing revenues when supply exceeds Manitoba customers' needs, and a supply when Manitoba Hydro is experiencing drought or emergency conditions.[248] The Electric Operations Statement shows significant forecast extraprovincial (or export) revenue of $1.283 billion for 2022/23 and a preliminary budget projection of $1.153 billion for 2023/24.[249] This extraprovincial revenue represents more than a third of Manitoba Hydro's total revenue during these years.

While Midgard's written evidence mentions the word "export" 55 times in 85 pages, Midgard was unwilling to agree that the forecast extraprovincial revenue is significant to Manitoba Hydro's customers.[250] There is ample information in the Application and on the record regarding Manitoba Hydro's system, export volumes, as well as historical and projected revenue and hydro generation. Midgard ignored this evidence and as a result, Manitoba Hydro submits that Midgard does not have a sufficient working understanding of Manitoba Hydro's generation system, how the generation assets are used, how the Manitoba Hydro system uses the export market to optimize the value of opportunity energy and be a source of imports in low water flow conditions, and the total revenue the generation brings to the corporation. This lack of basic understanding of the predominately hydro generation system, its market interactions and the revenue streams, all of which is evident from the Application, raises serious credibility concerns.

11.3. Manitoba Hydro's Market Interactions and Performance to Reliability Standards Are Fundamental to Providing Value to Manitoba Customers

Midgard asserts that "some or all" of Manitoba Hydro's assets could be permitted to degrade further without risk to ratepayers or the system:

> *"MR. MATTHEW GHIKAS: Sir, I'm going to read your own words back to you from page 51 of your evidence. "Consequently, the evidence indicates that*

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[248] MH-1, Application Tab 5, Figure 5.17, page 34.
[249] MH-1, Application Tab 4, Figure 4.2, page 7.
[250] Transcript May 25, 2023, pages 1848-1850.

> *Manitoba Hydro has sufficient surplus generation resources such that at least some or all of its generation assets can be permitted to degrade further before intervention is warranted from a ratepayer risk and system impact standpoint."*
>
> *Those were your words, right?*
>
> *MR. PETER HELLAND: Correct, those are my words. And let's be clear what 'some' means. 'Some' means near zero to some larger number. It -- it's a -- it's quite a range.*
>
> *And so, to characterize it as anything other than a range from near zero, effectively zero, to all would be a mischaracterization."* [251]

In Midgard's explanation of "some," it is unclear what, if any, supporting evidence they rely upon and therefore what, if any, value it provides. However, what is clear is that Midgard, in making these statements, has ignored and failed to address the importance of system reliability and mandatory reliability standards.[252]

Consideration of mandatory reliability standards that govern system operations are critically pertinent to any finding or recommendation that "at least some, or all, of its generation assets can be permitted to degrade further before intervention is warranted from a ratepayer risk and system impact standpoint."[253]

Manitoba Hydro applies a single, system-based approach to the evaluation of generation investments, which recognizes the obligation to serve the Manitoba load, existing export obligations, and the value obtained by domestic customers from interaction with external markets (i.e. exports and imports). This approach is applied in planning for resource adequacy consistent with industry standards and reporting of plans to NERC. Through prudent planning, the Manitoba Hydro system can continue to operate reliably and continue to adhere to reliability standards that govern its operations.[254]

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[251] Transcript May 25, 2023, pages 1852-1853.
[252] Transcript May 25, 2023, pages 1858-1859.
[253] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 51.
[254] MH-53, Undertaking #30, page 6.

Manitoba Hydro recognizes that its system performance and reputation in the market can materially impact value for Manitoba customers. One example is through Manitoba Hydro's Contingency Reserve Sharing Agreement with MISO, addressed in Manitoba Hydro Undertaking #30,[255] which demonstrates that absent sharing contingency reserves with MISO, to maintain reliable operations and compliance to NERC standards, Manitoba Hydro would have to immediately secure a large volume of spare capacity which would add significant costs to Manitoba customers. Allowing its system to degrade further, as suggested by Midgard, would negatively impact Manitoba Hydro's reliability performance and risk its reputation in the market, potentially jeopardizing the benefits of reserve sharing. Manitoba Hydro must maintain its system and not allow it to degrade further.

11.4. Generation Outages Have Revenue Impacts

As noted above, Midgard suggests that Manitoba Hydro has "sufficient surplus generation resources such that at least some, or all, of its generation assets can be permitted to degrade further before intervention is warranted from a ratepayer risk and system impact standpoint."[256] Manitoba Hydro submits that Midgard's reliance on Manitoba Hydro's response to Coalition/MH I-96a[257] and its incorrect extrapolation of logic that "the above confirmation that generation outages do not cause system outages"[258] demonstrates a fundamental misunderstanding by Midgard of the potential impact of generation forced outages on Manitoba Hydro's revenue ("customer risk") and the potential for system outages in the event of multiple outages during high system loading conditions.

Manitoba Hydro cannot achieve projected export revenue if its revenue-producing generation assets are "permitted to degrade further". Even if forced generation outages do not cause loss of load events ("system outages"), they are likely, under most water conditions, to result in some sort of negative impact to net export revenue through lower hydro generation. Under above average water conditions, the hydro generation outages can result in spilled energy and associated loss of export revenue. Under high load

[255] MH-53, Undertaking #30.
[256] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 51.
[257] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 51.
[258] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 51.

conditions when hydro generation is required to meet obligations, generator outages can result in costs for the purchase of replacement energy. Under average flow conditions, hydro generation outages can result in a shift of generation from the higher valued on peak period to the lower valued off-peak period. In all these situations, increased forced generation outages reduce net export revenue below that projected in the financial scenario, and ultimately impacts electricity rates Manitoba customers pay.[259]

Manitoba Hydro tracks indicative estimates of the lost revenue (opportunity costs) and increased purchase costs resulting from generation and HVDC outages. In 2022/23 alone, the lost opportunity cost of forced outages was estimated to be more than $70 million. This figure excludes any impacts of reduced future capacity surpluses related to degraded performance and/or the need to increase Manitoba Hydro's capacity Planning Reserve Margin if increased forced outages rates are sustained.

The fact that a single generating unit outage does not normally result in Manitoba Hydro being unable to serve domestic load or firm export contracts, does not in any way imply that multiple forced generation outages do not have the potential to cause domestic loss of load events, particularly under very high system loading conditions.

As stated in Appendix 5.5 of the Application, "Manitoba Hydro's capacity criterion requires that the corporation carry a minimum reserve which is intended to protect against capacity shortfalls resulting from breakdown of generation/transmission equipment or increases in winter peak load due to extreme weather conditions. The reserve is calculated as 12% of the Manitoba forecast peak winter demand in effect at the time for each year that is forecasted."[260] A sustained increase in the forced outage rate will result in a corresponding increase in the 12% planning reserve margin. New operable capacity resources would be required to replace the ones that Midgard suggests be allowed to "degrade further", at significant cost to Manitoba customers."[261]

11.5. HVDC Bipole Analysis is Deeply Flawed and Ignores Loss of Hydro Generation

Midgard has a fundamental misunderstanding about the potential impact of HVDC-forced

[259] MH-24, MH Rebuttal Evidence, pages 71-72.
[260] MH-1, Application Tab 5, Appendix 5.5, page 1.
[261] MH-24, MH Rebuttal Evidence page 72.

outages on Manitoba Hydro's load-serving ability, revenue, and customer impacts. For example, Midgard states that Manitoba Hydro "provides figure and explanatory text that shows with one Bipole failed (in this case Bipole II) all domestic load could be served, and even with two Bipoles failed, [emphasis in original] MH could still supply domestic load in most cases."[262]

Further, the Midgard report concludes:

> *"As a result, the ratepayer impact of a single Bipole failing is near zero, because there is sufficient redundancy in the DC and AC transmission systems to meet domestic loads even at peak times. And consequently, the criticality of the increased failure rates of Bipole I and Bipole II is lower than indicated by Manitoba Hydro when focusing on impacts at a system rather than asset level because it would take more than one Bipole failure, and typically more than two Bipole failures to result to result in an impact to domestic ratepayers."* [263]

Midgard's foregoing analysis and conclusions are incorrect. Manitoba Hydro's three HVDC Bipoles are generation outlet transmission which means they provide the only way (except for 200 MW of non-firm AC transmission) to move the hydro generation from the four Lower Nelson River generation stations (Keeyask, Kettle, Long Spruce and Limestone), with a combined capacity of approximately 4,200 MW[264] to southern Manitoba. Except for the 200 MW non-firm AC transmission provision, there is no ability for the Lower Nelson River generating stations to utilize the AC network to deliver its output to the major load centers in southern Manitoba.

Should two Bipoles fail, only 2,000 MW of north to south HVDC transmission would remain. Up to 2,200 MW of hydro generation would be stranded (or "bottled") in northern Manitoba and serving the Manitoba load would require imports of large volumes of replacement energy from markets outside of Manitoba, assuming availability to dispatch.

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[262] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, page 56.

[263] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 57.

[264] Coalition/MH I-99b).

Midgard could have estimated the impact of the loss of HVDC Bipoles as the Bipole load duration curves were provided in response to Coalition/MH I-99f. The abandonment of up to 2,200 MW of hydro generation in northern Manitoba would likely result in a near complete loss of export revenue ($1.283 billion for 2022/23 and a Preliminary Budget projection of $1.153 billion for 2023/24)[265] plus the cost of importing up to 1,400 MW of non-firm energy to meet firm Manitoba load of mostly on peak energy in the winter.[266] A single Bipole outage, depending on when it occurred, would also result in a lesser degree of bottled hydro generation in Northern Manitoba[267] and also has the potential for bulk power system outages.

Power systems often have unique characteristics. For Manitoba, the unique characteristics are that it is a predominately hydro system and over 70% of its generation is located on the Lower Nelson River connected to southern Manitoba through generation outlet transmission (i.e. the three Bipoles). This is different than in Alberta where Midgard has performed consulting services.

Alberta's predominately thermal power system added two HVDC Bipoles to the existing AC transmission system between the Calgary and Edmonton areas in 2014 and 2015. The AC transmission system between Edmonton and Calgary was reinforced to avoid reliability issues for consumers in southern and central Alberta, to improve the efficiency of the transmission system and to allow lower cost wind generation to supply northern loads. The existing AC transmission system in Alberta provides redundancy to the new Alberta Bipoles. No such firm AC transmission redundancy exists in Manitoba for the Lower Nelson River generation. If a single Manitoba Hydro HVDC pole or Bipole fails, power must flow on the other Bipoles or hydro generation will be restricted (and energy potentially spilled) in northern Manitoba. As such, redundancy for the generation carried on the HVDC transmission must be carried on the HVDC system itself. The complexity and the lead times for component replacement or modernizing of these assets is long (multiple years). Hence, in the event of a catastrophic failure of the Bipole(s), it could also take years to either replace that capacity with generation in southern Manitoba or replace major HVDC system components. Therefore, the effect of the lost capacity is long lasting and would likely extend through the winter peak demand months when the HVDC system

[265] MH-1, Application Tab 5, page 34.
[266] MH-24, MH Rebuttal Evidence, page 73.
[267] PUB/MH I-61a-b.

is typically most heavily relied on.[268]

11.6. Midgard Are Not Load Forecasters and its Load Growth Determination is Wrong

Midgard began its oral presentation with comments that “energy consumption growth rates have fallen since Manitoba Hydro's founding”[269] and “for the period from 1986 to 2019, the growth rate falls dramatically to 1.33 percent and, in the most recent fifteen (15) years, or fifteen (15) years of record that -- that we were able to obtain from Statistics Canada, it -- it's fallen to effective -- what is effectively a flat or near 0 (zero) electricity growth rate for Manitoba.”[270]

Manitoba Hydro provided an Electric Load Scenario in Appendix 5.1 of the Application. The Electric Load Scenario projects, net of program-based offerings provided by Efficiency Manitoba, that the Gross Firm Energy in Manitoba to grow 0.4% per year for the first 10 years of the forecast and 2.4% per year for the last 10 years of the forecast.[271] Manitoba Hydro submits that this is the most reliable data for the PUB to rely upon for load growth in Manitoba.

Conversely, the data in the graph presented by Midgard[272] is not load or consumption as the slide title “Growth Rates Have Fallen…” implies. Rather, it appears to be actual gross generation in Manitoba, including power generated for Manitoba load and exports. Significant downturns in the data occur around 1988 and 2003, years in which Manitoba experienced significant drought. Midgard suggests the data shows that “electrical energy growth experienced a major decline that appears to have recovered by the early 1990’s.”[273]

Manitoba Hydro does not dispute that the rate of load growth in Manitoba has dropped significantly since the 1960’s. However, Midgard’s conclusion of “flat or near zero electricity growth rate for Manitoba” is incorrect because the underlying data was not

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[268] MH-24, MH Rebuttal Evidence, page 74.
[269] Transcript May 24, 2023, page 1577.
[270] Transcript May 24, 2023, pages 1577-1578.
[271] MH-1, Application Tab 5, Appendix 5.1, page 3.
[272] CC-15, Midgard Consulting Presentation, May 24, 2023, slide 8; CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 16.
[273] CC 8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, page 16.

load or consumption. As noted above, the underlying data appears to be gross generation in Manitoba which, while subject to flow related variation, tends to be flat during periods in which there is no major system expansion.

Presenting generation data as consumption is incorrect and misleading. Explaining the pattern during the drought of the late 1980's as a decline and then followed by recovery in growth as Midgard has done indicates a lack of care in use of data and analysis, upon which Midgard formed its opinions, and its lack of understanding of the role the export market plays in balancing supply and demand on the Manitoba Hydro system.

11.7. Capacity is Not Sitting Completely Idle Most of the Year

Regarding Manitoba Hydro's level of surplus capacity, Mr. Oakley stated that, "[m]ost of the year, a lot of that capacity is sitting completely idle."[274] This statement is incorrect and demonstrates Midgard's lack of understanding of how Manitoba Hydro operates its entire system.

Generation statistics are provided by Manitoba Hydro each year in its annual report. Manitoba Hydro's most recent annual report, for the Year Ended March 31, 2022 indicates the sources of electrical energy generated and purchased for a total hydro station net capability of 5605 MW and 26.6 TWh of hydro generation in a drought year.[275] Figure 2 of MFR 42 shows projected hydro generation for 2022/23, a high-water year, of 40.9 TWh. These numbers represent annual hydro generator operating factors with a range of 55% (in drought) to 84% (high water) with the middle around 75% average annual operating factor based on the later year's hydro generation in Figure 2 of MFR 42. Manitoba Hydro submits that contrary to Midgard's analysis, most of the year, "a lot" of its hydro generator capacity is not sitting completely idle.

11.8. Manitoba Hydro no Longer has Large Surpluses

Midgard states that "MH's evidence demonstrates that its system is overbuilt with

[274] Transcript May 25, 2023, page 1796.
[275] MH-1, Application Tab 3, Appendix 3.1, pages 10, 42.

respect to meeting domestic needs."[276] As explained in Section 6.10, Manitoba Hydro has only a sliver of surplus annual capacity available until 2030/31, and the anticipated need date for new capacity resources is 2030/31 based on sustained winter peak capacity deficits. Contrary to Midgard assertions, the Manitoba Hydro load is growing. As the Manitoba Hydro load grows, capacity and dependable energy that was once surplus to Manitoba is required to serve the Manitoba load in accordance with Manitoba Hydro's legislative obligation and mandate. To the extent Manitoba Hydro's existing commitments include long-term sales of capacity and dependable energy, Manitoba Hydro does not intend on entering into any long-term contract which would accelerate the need for new resources in Manitoba.

11.9. Midgard has Misconstrued the Economy of Scale Argument and Export Strategy

Midgard states that "Manitoba Hydro is continuing a six-decade old strategy of over-investing in capital assets to serve export markets."[277] However, Midgard also acknowledges that Manitoba Hydro is "signaling of a pending shift away from its historical level of reliance on export market revenues as implied in Strategy 2040."[278] Clearly, Manitoba Hydro is not "over-investing" in capital assets to serve export markets.

Midgard misrepresented historical background information provided by Manitoba Hydro that "[t]he clear benefit of building hydro for domestic need while using markets external to the province to **optimize the investments** was recognized more than sixty years ago."[279] [**emphasis added**] Optimizing is not the same thing as over-investing. Even if Manitoba Hydro had a perfect balance of capacity and dependable energy to meet its domestic load, Manitoba Hydro would still benefit from large interconnections to monetize the up to 10 TWh of opportunity hydro energy that is available in some years. In addition, large interconnections provide access to contingency reserves and other benefits, as discussed in Section 11.3.

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[276] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 84.
[277] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 6.
[278] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 78.
[279] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 15.

11.10. Manitoba Hydro is Focused on the System Approach

Midgard incorrectly suggests that "despite its asset management policy of focusing on system impacts rather than individual assets, MH continues to justify generation asset investments on an asset focused basis rather than a system focused basis."[280]

Manitoba Hydro focuses on the entire and integrated operation of its overall system when considering and justifying generation asset investment. Manitoba Hydro operates an integrated system in which all available generation resources are operated as required to meet Manitoba load, while considering its market interactions on a least cost basis. For this reason and as explained further below, the incremental or marginal generation resulting from any single project is not individually allocated to serving domestic load or export and import market interactions.

12. MINIMUM SYSTEM CONCEPT IS ARBITRARY & UNWORKABLE

During the proceeding, Midgard advocated that Manitoba Hydro should determine its "minimum system", or the portion of the existing system that is required to serve domestic customers reliably. For the reasons outlined below, there is no method for Manitoba Hydro to reasonably allocate or estimate costs between domestic service and export activities as advocated by Midgard.

For context, there are differences in the level of details available for the four broad cost components that make up Manitoba Hydro's revenue requirement:

- Manitoba Hydro maintains accounting records that track the investment and depreciation expense for generation and transmission assets at the location level.
- Finance expense and capital tax are not associated with any specific assets in Manitoba Hydro's accounting records. Implementing a minimum system approach would require developing a means to attribute these expenses to specific facilities.
- Operating expense can be attributed to specific generating stations using the settlement cost centre view that is used to prepare the Cost of Service Study.
- Water rentals and fuel costs can be associated with individual generating stations.

[280] CC-8, Consumers Coalition Intervener Evidence, Midgard Consulting Incorporated, April 3, 2023, page 52.

Once the direct costs have been determined for these facilities, there are still significant shared/common costs that would need to be allocated to these facilities on a yet to be determined basis to encompass the full revenue requirement. The appropriate treatment of costs that may also be viewed as generation or transmission related, such as mitigation, would need to be considered in addition to the overhead type costs that are more general in nature.

The difficulty with the minimum system approach is not necessarily due to granularity of accounting costs, rather with the task of defining and achieving consensus on the portions of the system that are surplus to domestic needs.

The typical implementation of the minimum system approach is to identify the customer and demand related portions of the distribution system in cost allocation studies. Despite the long standing and widespread use in this context, there is still considerable controversy implementing the approach even for comparatively simple distribution systems. The difficulty in apportioning the much more complex and interrelated Generation and Transmission system using a theoretically similar approach cannot be underestimated. This complexity is compounded substantially in the case of Manitoba Hydro's system because of its connectivity to neighbouring markets.

Manitoba Hydro has a significant history attempting to implement an export class in its Cost of Service Study, which in concept is similar to the minimum system in that the goal is to isolate revenue requirement into domestic and export related portions. Manitoba Hydro began exploring incorporating an export class in the Cost of Service Study in 2003 and the approach was abandoned in 2016 due to the inability to reach any consensus about the portion of the G&T system that should be allocated to export customers rather than domestic customers. As explained at page 30 of Board Order No. 164/16:

> *"Existence of an Export Class*
>
> *The original reasons for a separate Export class were discussed in a 1988 report from the Board to the Minister.[281] In this report, the Board recommended that revenues and costs related to export sales be*

[281] Board Report to the Minister of Energy and Mines, March 31, 1988.

segregated in Manitoba Hydro's accounting records in order to demonstrate that domestic customers are not subsidizing export sales. To accomplish this, the Board suggested the method of treating export sales as a separate customer class in the COSS. In addition, Manitoba Hydro has explained that the creation of an Export class was to promote fairness, including a means of returning export revenues to domestic customers on a basis that Manitoba Hydro considered to be fairer."

The reasons for the existence and issues surrounding the Export Class were also explained by the Board at page 30 in Order 164/16:

"The Treatment of Export Revenue:

Manitoba Hydro plans its system so that it meets two planning criteria: (1) having sufficient generation under minimum, or what is referred to as dependable, water flows, and (2) having sufficient generation to meet the maximum winter peak demand. Because the dependable flow condition is based on the worst drought conditions in Manitoba Hydro's one hundred year hydrological record, in water years with more water than such extreme drought, there is surplus generation available that may be exported. Manitoba Hydro also must have sufficient generation capacity to meet Manitoba Hydro's customers' peak electricity demands plus an operating reserve margin. Hydroelectric generating stations are built with substantial capacity such that large amounts of generation, with long lead times, are added to Manitoba Hydro's system in large increments resulting in surplus generation even under dependable flow conditions. The combination of these effects means Manitoba Hydro has surplus generation that can be exported to earn additional revenue."

Ultimately, the Board decided in the Board Findings at page 32 of Order 164/16 to abandon the Export Class:

*"The Board finds t*hat an Export class should not be used in the COSS.
First, the Board notes the general agreement of the experts and parties in this proceeding that the use of an Export class is not an appropriate way to

*measure or determine whether Manitoba Hydro's decisions to proceed with particular capital projects were economically sound. The Board concludes that the Export class is not a vehicle for measuring the profitability of Manitoba Hydro's export business**, nor is it possible to use the COSS to measure risks associated with the export venture or the prudence of any resource development plans**."* [**emphasis added**]

The integrated nature of the predominately hydro system and its complex flow and load driven market interactions make any exercise to tease apart domestic and export costs an arbitrary exercise which provides no insight into the objective of determining export profitability. Manitoba Hydro applies a single, system-based approach to the evaluation of generation investments, which recognizes the obligation to serve the Manitoba load, existing export obligations, and the value obtained by domestic customers from interaction with external markets (i.e., exports and imports). Through these interactions, Manitoba Hydro's system performance and reputation in the market can materially impact value for Manitoba customers.[282]

13. WHAT MANITOBA HYDRO IS HEARING FROM CUSTOMERS ON RELIABILITY AND RATES

As discussed in Tab 3 of the Application, in establishing the projected rate path included in Appendix 4.1 of the Application, Manitoba Hydro considered what it has heard directly from customers. Although Manitobans, as expected, continue to stress the importance of low Manitoba Hydro rates, when asked to weigh the importance of lower rates versus tradeoffs in reliability, customers have indicated that reliability of products and services is more important and must be balanced.[283] This indicates that the health of the overall system, and ability of Manitoba Hydro to deliver a reliable customer-centric service, is an important factor when considering rate increases.

Throughout the hearing and the GRA process, Manitoba Hydro has been asked to defend its position that Manitobans are looking for balance between reliability and cost. Although Manitoba Hydro openly acknowledged in its Rebuttal Evidence that the research conducted was not designed to be a comprehensive investigation of trade-offs,[284] the results are still directionally sound, statistically valid, and appropriate to use

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[282] MH-53, Undertaking #30.
[283] MH-1, Application Tab 10, MFR 12.
[284] MH-24, MH Rebuttal Evidence, page 5.

as a guiding principle in the Application. Beyond the research, the importance of reliability is further validated by the perspectives of MIPUG who indicate that reliability, power quality and customer service are a top concern for industrial customers, and "the industrial customers have proffered the evidence of Mr. Bowman that highlights general support for the overall level of increases proposed by Hydro, based largely on the spending forecasts prepared by Hydro in the Financial Forecast Scenario".[285]

In oral testimony, Manitoba Hydro acknowledged that the results of the Customer Perception and Tracking Study show that the average Manitoban's satisfaction with price was lower than the satisfaction levels of overall service and of reliability.[286] Naturally, and understandably, Manitoba Hydro acknowledges that customers look to keep their expenses low and minimize the impact on their wallet. As such, it is anticipated that a price satisfaction question that asks solely about satisfaction with price would score lower than others, especially when the question does not ask about value for price or what the customer would be willing to pay for trade-offs in services and products provided.

Acknowledging this need and desire for lower cost makes the results of the customer research focused on trade-offs even more compelling. In 2019, Manitobans were similarly dissatisfied with price. In the 2019 Customer Values and Perceptions Study,[287] respondents indicated "keeping rates as low as possible" a top priority. Yet, when asked to think about how to manage reliability, respondents still chose midrange responses that indicate maintaining or improving reliability versus keeping rates lower by cutting costs. In 2022, the Leger Reputation study[288] found reliability versus value to be the more foundational element of Manitoba Hydro's reputation. The fact that Manitobans would pass up the opportunity to lower rates if it meant decreased reliability is important and further validates the principle of balance.

With respect to the stated preference studies conducted in British Columbia and Ontario, these studies show potential in helping to clarify the preferences of Manitobans on cost and reliability. Importantly however, these studies fail to analyze the other important values and considerations that are important components of a Manitoba Hydro general

[285] MIPUG-7, MIPUG letter to PUB re: Pre Hearing Conference #2, April 5, 2023, page 1-2.
[286] Transcripts, June 8, 2023, 3935-3938
[287] MH-1, Application Tab 10, MFR 12, Attachment 1.
[288] MH-1, Application Tab 10, MFR 12, Attachment 2.

rate application. The importance of Indigenous reconciliation, environmental stewardship, asset management, risk tolerance and financial stability are not analyzed in the methods submitted which gives an incomplete view of the preferences of respondents.

To be clear, although Manitoba Hydro did not establish its rate path based solely on customer feedback, the principle of balance was foundational to the Application. The importance of achieving an appropriate balance versus an approach fixated on the lowest possible cost is validated and two separate research programs which indicate that Manitobans value maintaining or improving reliability over lowest possible rates. While no single research program will ever be able to perfectly capture customer perspectives on balancing competing priorities in Manitoba Hydro's GRAs, the evidence filed by Manitoba Hydro is a compelling and important step in understanding and valuing this perspective. Manitoba Hydro remains committed to obtain robust customer research and feedback to inform future general rate applications with its overarching legislative mandate to supply safe and reliable power to Manitobans.

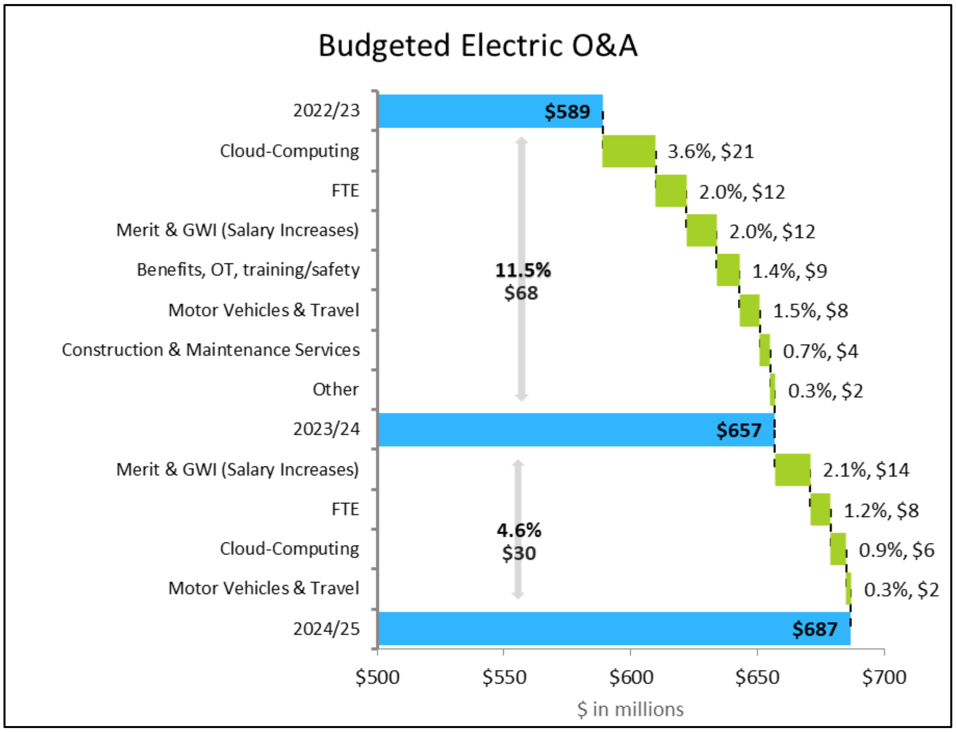
14. OPERATING & ADMINISTRATIVE COSTS

14.1. Increases in O&A Expenses are Required

Increases in Operating and Administrative ("O&A") expenses are required to ensure that Manitoba Hydro can maintain its electric system and continue to provide reliable service and meet the current and future needs of customers. Manitoba Hydro remains committed to effectively managing its costs and has made concerted efforts to reduce O&A expenses.

The figure below provides a summary of the O&A increases in 2023/24 and 2024/25 included in the revenue requirement.

Figure 22[289]



Based on the summary of O&A increases shown in the chart above, Manitoba Hydro is concerned with and strongly opposes Mr. Rainkie's unrealistic and unachievable recommendation that O&A should only be allowed to increase by 2% from 2022/23 given the cost realities of Manitoba Hydro. It is unclear what Manitoba Hydro would not do, or could "cut", if it was held to a 2% increase in O&A for 2023/24.

As stated in direct evidence by Ms. Amorim Dew:

> *" ...2 percent is related to merit and general wage increases. As I've stated 80 percent of our work force is unionized and there is little control over this increase. If that is the only increase we are allowed from 2022/23, then no other increases are possible, including cloud computing, increasing our FTE, costs related to motor vehicles and travel, other costs associated with our staffing, such as benefits, overtime, training and safety, or any maintenance services which the increases included in '23/'24 are related to*

[289] MH-42, MH Revenue Requirement Presentation, May 29, 2023, slide 25.

increasing vegetation management, which we are lagging behind industry standards.” [290]

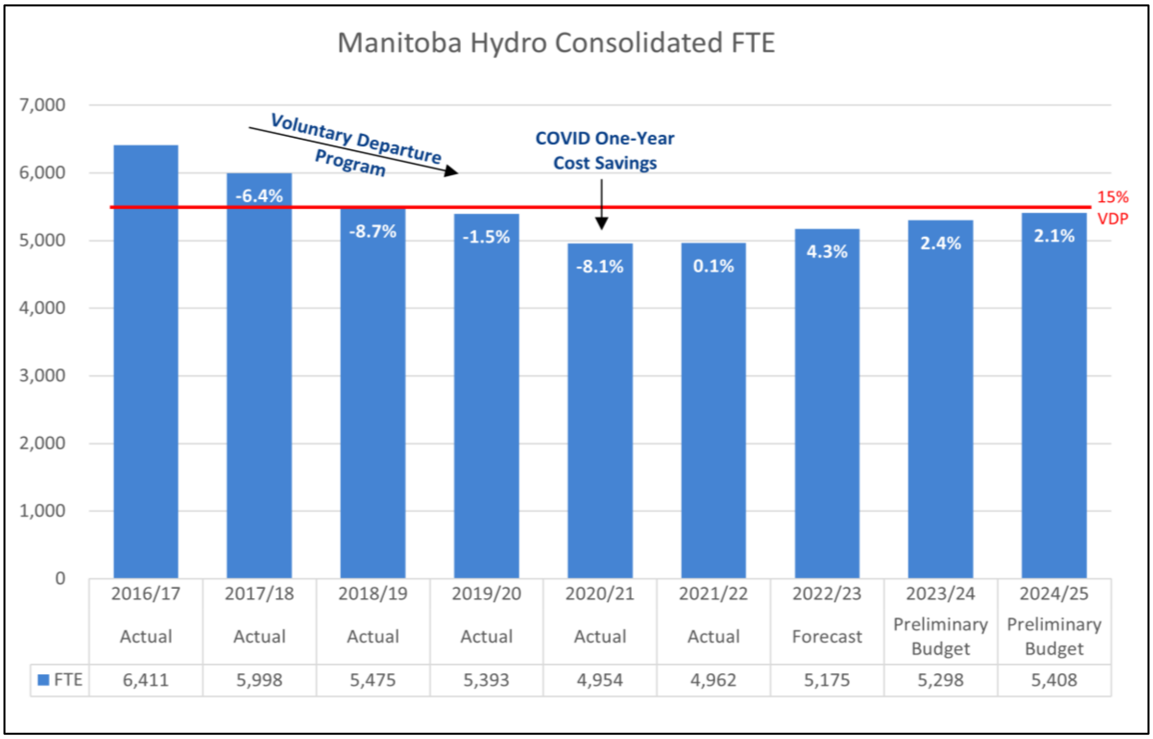
14.2. FTE Increase is Required to Ensure Reliability is Maintained and Customer Needs are Met

Manitoba Hydro has experienced an almost 25% reduction in FTEs from 2016/17 through 2021/22 due to the Voluntary Departure Program (“VDP”) and the government cost savings initiative in 2020/21 related to the COVID-19 pandemic.

As shown in the figure below, Manitoba Hydro intends to maintain the 15% reduction of its workforce through the Test Years, but it is necessary to rebuild its workforce due to the reduction experienced through the pandemic. The increase in FTEs is necessary to ensure Manitoba Hydro continues to provide safe and reliable service and respond to customers’ current needs and future expectations.

[290] Transcript May 29, 2023, page 1999.

Figure 23[291]



Note: FTEs include full time, part time, terms, seasonal, students and subsidiary (Centra, Manitoba Hydro International (MHI) and Manitoba Hydro Utility Services (MHUS)) employees.

Mr. Madsen stated in his direct evidence that:

> *"Care must be taken to ensure Manitoba Hydro has sufficient resources to provide safe and reliable services to customers; that's in my mind, a given."*[292]

Manitoba Hydro agrees with Mr. Madsen on this point. As stated extensively through this hearing, Manitoba Hydro does not have the required staffing levels to meet Manitobans' current and evolving energy needs:

- Manitoba Hydro is falling behind on the maintenance of its aging assets, which impacts reliability. With current resources, Manitoba Hydro is only completing 75% of

[291] MH-42, MH Revenue Requirement Presentation, May 29, 2023, slide 26.
[292] Transcript June 2, 2023, page 2892.

planned maintenance on its assets.[293]

- Manitoba Hydro is also significantly behind industry standards on vegetation management. Industry standard is to maintain a tree trimming cycle time of 6 years, Manitoba Hydro is at 17 years. This contributes to increased outages.[294]
- Commercial and industrial customers are telling Manitoba Hydro that reliability and responsiveness are critical to their business effectiveness. [295]
- Service connection durations for commercial and industrial customers have increased from 360 days to 432 days between 2019 and 2022.296 Of these customers, 49% indicated their project was not completed in a reasonable amount of time.[297]

Mr. Madsen has recommended that Manitoba Hydro should only increase FTE by 1% (52 FTE) in 2023/24 rather than the 2.4% (123 FTE) increase budgeted.

As outlined in the figure below, the FTE increase planned in the budget years is focused on rebuilding the trades and professional trainee programs which are critically required to address attrition and meet customer service level expectations. Based on Mr. Madsen's suggestion to increase by only 52 FTEs in 2023/24, Manitoba Hydro would not be able to hire more than half of the trades trainees that it has planned to, as shown in the table below. This means that safety, reliability and customer timelines would be at risk and most likely continue to deteriorate. As such, Manitoba Hydro does not accept Mr. Madsen's recommendation that the planned increase in FTEs should be reduced.

Figure 24[298]

Figure 6.5 Planned Recruitment for Trades Trainees (FTEs)

Fiscal Year	FTEs
2022/23	89
2023/24	129
2024/25	112

[293] Transcript May 15, 2023, page 187.
[294] MH-1, Application Tab 6, page 37.
[295] MIPUG-7, MIPUG Letter to PUB re Hearing Conference, page 1.
[296] MH-1, Application Tab 6, page 11.
[297] MH-24, MH Rebuttal Evidence, page 6.
[298] MH-1, Application Tab 6, Figure 6.5, page 13.

14.2.1. Comparison of FTE by Business Unit Starting in 2019/20 is Not Appropriate

Mr. Rainkie states that "97 FTE increase (2020 to 2025) [is] entirely in Governance & Services business units primarily due to Strategy 2040."[299] This comparison is inappropriate and misleading.

Mr. Rainkie's suggestion that FTE growth is mainly in the Manitoba Hydro Governance & Services business units and is driven by Strategy 2040 does not accurately reflect FTE changes since implementation of the VDP and takes a narrow view of what is included as part of Strategy 2040.

Through the VDP, Manitoba Hydro committed to reducing its workforce by approximately 15%. As evidenced in Figure 23 above, Manitoba Hydro has maintained that reduction through the Test Years of this Application.

The VDP was not a targeted reduction of specific positions that were no longer required at Manitoba Hydro; it was intended to reduce the workforce by approximately 15%. The program provided a financial incentive to those employees that voluntarily chose to leave Manitoba Hydro and resulted in departures across the corporation. As such, comparing FTE by business unit starting in 2019/20 is not appropriate as the reduction was a corporate reduction and each business unit was not in an "ideal state" at that point in time. As discussed by Ms. Amorim Dew:

> *"… we can compare 2019/'20 to our test years. We definitely can do that, but that really isn't a fair comparison especially at a business unit level. We compare ourselves all the time to 2016/17, which is when we did the voluntary departure program. As I've already said in my direct and in some responses through this Hearing, the voluntary departure program was an initiative to have a financial reduction through reduction of our workforce, which we are maintaining through the test years. And so, there were not deliberate positions that were eliminated or deemed not required. We're doing a lot of work now through the business model review to have the right people in the right place to*

[299] CC-20, Darren Rainkie Direct Evidence Presentation, June 1, 2023, page 20.

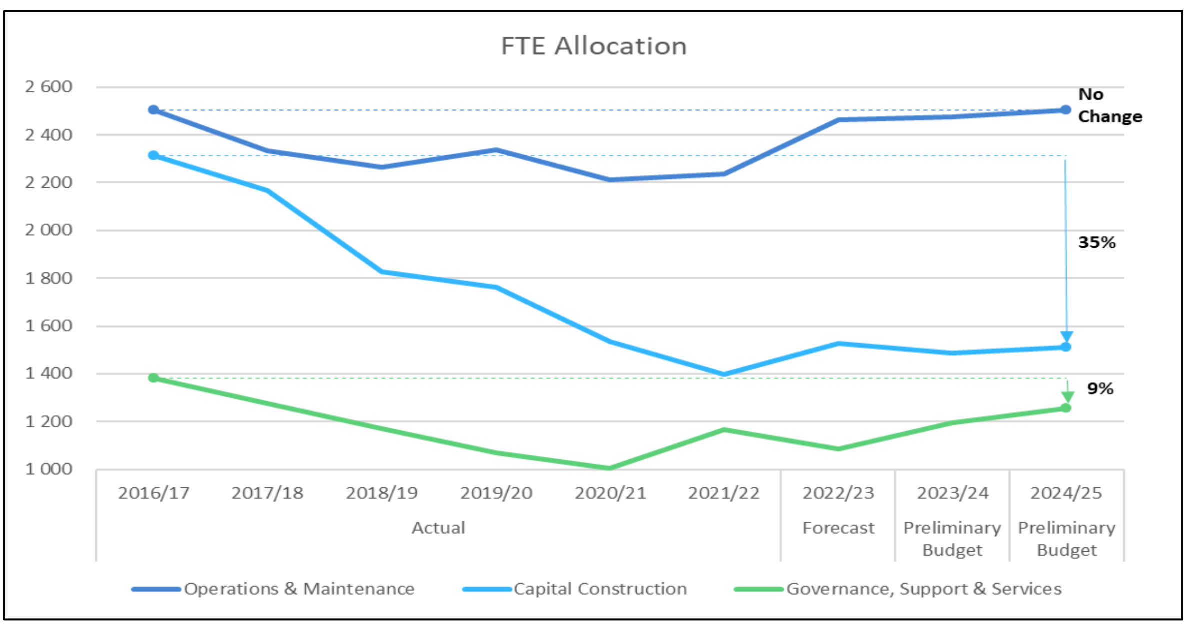
ensure that the work is properly getting done. So the customer service isn't impacted and reliability isn't impacted greater than it has. But I just want to comment that comparing to 2019/'20 by business unit is not a fair comparison." [300]

The Business Model realignment has resulted in a significant restructure of the business units and has identified where FTE growth is required to ensure reliability, to improve customer response times, and to catch up on maintenance of Manitoba Hydro's assets.

Based on the planned recruitments for Trades Trainees shown in Figure 6.5 of Tab 6 of the Application (and above in Figure 24), it is evident that the FTE increase is predominantly focused on rebuilding the pool of trades trainees.

Contrary to Mr. Rainkie's assertions, the majority of FTE growth is specific to operations and maintenance and not on governance, support and services, as evidenced in the figure below.

Figure 25[301]



[300] Transcript May 30, 2023, page 2309.
[301] MH-42, MH Revenue Requirement Presentation, May 29, 2023, slide 28.

14.3. Substantially all of Manitoba Hydro's O&A Expenses are Subject to Inflationary Pressures and Increases

Mr. Rainkie has incorrectly stated that 80% of O&A costs go up by 1.5% to 2% in line with general wage increases ("GWI"). While Manitoba Hydro presented that over 80% of O&A costs are related to staffing, it is not accurate to state that all of those costs are tied to GWI and the remaining 20% may be tied to CPI as Mr. Rainkie has suggested:

> *"MR. SVEN HOMBACH: Could you comment whether, in light of inflation actually being quite a bit higher now than it was in 2019, that a 1 percent escalator is still appropriate?*
>
> *MR. DARREN RAINKIE: Well, it -- I've gone through it a couple of times and hopefully it's clear, Mr. Hombach. And let me -- let me try again and you tell me if it's not clear. Manitoba Hydro's evidence is 80 percent of its costs are going to move along the lines of wages and salaries, right? And the 20 percent of its costs will have more reference to the level of CPI.*
>
> *So back-of-the-envelope calculation, if I take 20 percent of $600 million, that gives me $120 million of costs that might move in line with inflation. You know, and so, if I say, Well, inflation is, you know, 4 percent higher, if I take 4 percent times $120 million, I might get $5 million, if I'm doing my math correctly. And so, that would -- that could be the potential of the impact on Manitoba Hydro of that higher CPI."*[302]

Wages and salaries are tied to GWI amounts, merit and progression. As Manitoba Hydro has advised, GWIs have not been settled for all bargaining units and Manitoba Hydro's largest union IBEW, which represents almost half of its workforce, is currently in negotiations.[303] CPI is one of the many considerations that all unions across the country are factoring in when putting forward positions for GWI and CPI is also one of the factors that arbitrators and adjudicators consider when awarding GWI.

While other costs were identified as "employee related" it should be noted that they

[302] Transcript June 1, 2023, pages 2833-2834.
[303] PUB/MH I-73a; Transcript May 29, 2023, page 1994.

would not be tied to GWI but are more appropriately tied to CPI increases at a minimum:

- Fuel prices today are at least 60% higher than they were in 2019/20,[304] which is a slight drop from where fuel prices were at in 2022/23 when this Application was filed;[305]
- Motor vehicle costs, including parts and repairs, are contributing to significant increases in O&A as Manitoba Hydro is holding on to fleet longer due to supply chain challenges;[306]
- Safety equipment and training costs are increasing with the increase in trades trainees – these cost categories reflect larger increases that are tied to an increase in trainee levels, rather than increasing in line with CPI; and
- Meals, mileage, and accommodations are all increasing in line with CPI and would also see larger increases due to an increase in trainees.

As a result, almost all of Manitoba Hydro's O&A costs are subject to inflationary pressures and cannot be tied to a 1.5% to 2% GWI as Mr. Rainkie has incorrectly suggested.

14.4. Additional O&A Increases are Required to Ensure the Reliability of Manitoba Hydro's System

While it has been recognized throughout this proceeding that there are inflationary increases impacting O&A expenses, increases are not only due to inflation. Manitoba Hydro is increasing O&A costs in various areas to ensure that it can continue to achieve its legislative mandate of providing safe, clean and, reliable energy.

In addition to an increase in FTE, which is predominantly focused on rebuilding operational capability through a reinstatement of necessary trainee programs, there are increases in maintenance work required on Manitoba Hydro's assets:

> *"MR. CYRIL PATTERSON:… some of the realities in our environment for hiring the highly skilled labour force that we need to do these types of repairs, internal labour takes at least four (4) years for them to become qualified, in order to do this highly-skilled hazardous work…*

[304] MH-1, Application Tab 6, page 28.
[305] MH-1, Application Tab 6, page 28.
[306] MH-1, Application Tab 6, page 28.

MR. BOB PETERS: And you're trying, Mr. Patterson, to onboard those resources now, but you're still telling the Board you're going to be a number of years out before you -- you're going to have the complement that you need to do that?

MR. CYRIL PATTERSON: Correct. Yes. We're a training utility. So, it's most of our trades program are four (4) years and, in order for these folks to be highly-skilled and qualified to do the work safely that they need to do, they need that full scope of that four-year training program." [307]

Vegetation management is one of Manitoba Hydro's maintenance programs that has fallen behind due to cost constraint measures and a reduction in resources. Vegetation is a risk that needs to be managed as part of an electric utility's transmission and distribution systems. If unmanaged, vegetation can fall into lines, impacting reliability and safety.

A key measurement of how well a utility is maintaining its vegetation is its tree trimming cycle time, i.e. how often a utility returns to an area to maintain vegetation. It is industry standard to maintain a tree trimming cycle time of six years. Manitoba Hydro's current estimate of its cycle time, province-wide, is 17 years. Given that tree contacts are the primary cause for 24% of disruptions on the overhead distribution system, Manitoba Hydro is working to increase its vegetation management to improve its cycle time and work towards a target more in line with the industry.[308]

The table below summarizes the vegetation management expenditures for 2021/22, the forecast for 2022/23 and the planned vegetation management for the Test Years.

[307] Transcript May 23, 2023, pages 1310-1311.
[308] MH-1, Application Tab 6, page 37; COALITION/MH I-24b.

Figure 26[309]

Figure 6.22 Vegetation Management, 2021/22 – 2024/25

	2021/22	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget
Operational expenses	11 518 925	13 789 983	15 665 577	16 338 684
% change		*19.7%*	*13.6%*	*4.3%*
Labour charges	4 725 914	6 023 739	6 632 975	6 820 827
% change		*27.5%*	*10.1%*	*2.8%*
Total Vegetation Management	**16 244 840**	**19 813 722**	**22 298 552**	**23 159 511**
% change		*22.0%*	*12.5%*	*3.9%*

Manitoba Hydro uses both internal resources and contracted services to conduct vegetation management work. Operational expenses, as shown in in the figure above, primarily consist of contracted costs that do all of the vegetation management on the distribution system and approximately half of the vegetation management on the transmission system. Internal resources are used for approximately half of vegetation management work done on the transmission system. The increase in maintenance work is increasing the proportion of work that is operating, thereby reducing the capitalization rate Manitoba Hydro is experiencing (which increases overall O&A expenses).

14.5. Consulting Costs are Necessary for Business Requirements

In 2022/23, there were several other significant pieces of work that necessitated the use of consulting and professional services, including:

- Development of Manitoba Hydro's first integrated resource plan;
- Asset management maturity assessment;
- Assistance in the development of centers of expertise in project management and asset management following the business model changes and the integration of generation, transmission and distribution under these groups; and,
- Staff augmentation for short term and/or specialized needs that Manitoba Hydro did not have internally.

Mr. Madsen is recommending that consulting costs should only be allowed to increase by

309 MH-1, Application Tab 6, page 37.

4% from 2021/22 – after removal of cloud/SAP costs.[310] Mr. Madsen is not considering significant increases in this cost category which would not allow for costs to be held to the 2021/22 level. With the final unit of the Keeyask Generating Station being placed into service on March 9, 2022,[311] almost all of the O&A costs associated with the Keeyask Generation Station are incremental costs in 2022/23. The Operational Expenses associated with environmental monitoring and partnership requirements for that generating station primarily fall within the consulting and professional fee costs category, as outlined below.

Figure 27[312]

Figure 6.21 O&A Costs for New Assets associated with the Major Projects

	2022/23 Forecast			2023/24 Preliminary Budget			2024/25 Preliminary Budget		
	Operational Expenses	Labour	Total	Operational Expenses	Labour	Total	Operational Expenses	Labour	Total
Keeyask Generating Station	8 335 017	5 508 883	**13 843 900**	9 052 170	5 981 919	**15 034 089**	10 391 910	6 121 754	**16 513 664**
Bipole III Transmission Line	309 383	544 755	**854 138**	435 368	545 265	**980 634**	560 793	560 654	**1 121 447**
Riel Converter Station	1 581 981	5 503 736	**7 085 717**	1 617 526	5 201 265	**6 818 791**	1 660 681	5 413 617	**7 074 298**
Keewatinohk Converter Station	902 408	3 448 883	**4 351 291**	930 347	3 894 317	**4 824 664**	964 899	3 992 080	**4 956 979**
Manitoba Minnesota Transmission Line	4 287	95 713	**100 000**	4 372	97 628	**102 000**	25 892	578 148	**604 040**
Birtle Transmission Line	4 113	20 887	**25 000**	45 328	230 172	**275 500**	4 279	21 731	**26 010**
Total	**11 137 188**	**15 122 857**	**26 260 045**	**12 085 112**	**15 950 566**	**28 035 678**	**13 608 455**	**16 687 983**	**30 296 438**

Manitoba Hydro provided further details of what is driving the increases in Consulting and Professional Fees during its direct evidence for the revenue requirement panel, which is driven primarily by the shift to cloud-computing arrangements and the current SAP system replacement in 2023/24 and 2024/25.[313]

Mr. Madsen also stated in his testimony that, "[o]nce staff are hired, the costs to remove those staff, if not necessary, can be significant."[314] Manitoba Hydro agrees with that statement; a component of the consulting costs identified above is for staff augmentation in line with Mr. Madsen's suggestion. However, it should be noted that staff augmentation results in an increase in consulting expenses. While that is the appropriate decision to make when there is a short-term need or when expertise is not available internally, one cannot suggest that both labour costs and consulting expenditures be reduced simultaneously if a specific and immediate business need necessitates resources.

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310 Transcript June 2, 2023, page 2902.
311 MH-1, Application Tab 6, page 35.
312 MH-1, Application Tab 6, page 36.
313 MH-42, MH Revenue Requirement Presentation, May 29, 2023, page 30.
314 Transcript June 2, 2023, page 2892.

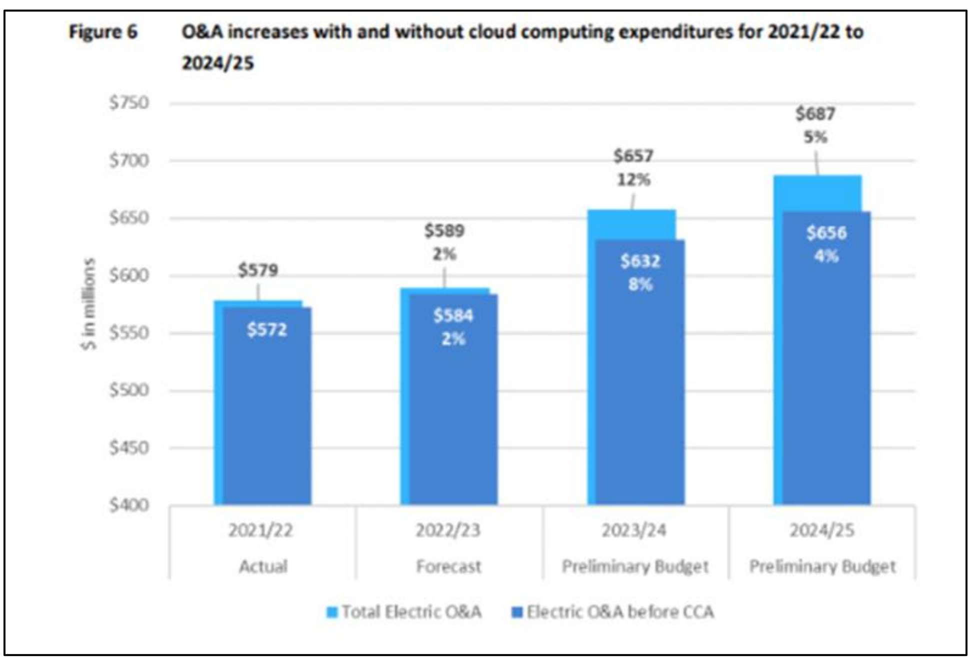
Manitoba Hydro has primarily been using staff augmentation in its digital and technology business unit for cyber security and other more specialized needs.

14.6. Shift to Cloud Computing is Resulting in Incremental Increases to O&A

Manitoba Hydro has a technology debt that needs to be addressed.[315] The shift to cloud computing is in line with industry best practice to leverage new technologies, improve cyber security and facilitate continuous improvement.

Costs related to cloud computing are one of the primary causes of O&A increases in 2023/24, contributing to almost one third of the increases from 2022/23. Historically, most IT expenditures were capitalized as they were on-premise and eligible for capitalization. With the shift to cloud-based services, which was accelerated with remote work requirements during the pandemic, cloud computing arrangements are generally deemed to be an operating expense. This started to impact Manitoba Hydro's O&A actuals in the 2021/22 fiscal year. The following figure shows Manitoba Hydro's O&A increases with and without cloud computing expenditures from 2021/22 to 2024/25.

Figure 28[316]



[315] MH-1, Application Tab 6, pages 29-30.
[316] MH-24, MH Rebuttal Evidence, page 13.

The budget for 2023/24 and 2024/25 includes costs related to consulting and computer services for small cloud-based services, as well as an estimate for the replacement of Manitoba Hydro's current Enterprise Resource Planning system – SAP ECC, as shown in the figure below. Manitoba Hydro is currently developing the business case (including a readiness assessment) for the SAP ECC replacement, with a Fall 2023 completion date planned for that business case.

Figure 29[317]

MANITOBA HYDRO CLOUD COMPUTING ARRANGEMENT COSTS				
(in Millions)	**2021/22 Actual**	**2022/23 Forecast**	**2023/24 Preliminary Budget**	**2024/25 Preliminary Budget**
SAP S/4HANA				
Operational Expenses	$0	$0	$11	$20
Internal Labour	0	0	2	3
SAP S/4 HANA CCA Costs	**0**	**0**	**13**	**23**
Small Software Sytems				
Operational Expenses	4	2	11	7
Internal Labour	2	3	2	2
Small Software Systems CCA Costs	**6**	**5**	**13**	**9**
Total - Cloud Computing Arrangement Costs	**$6**	**$5**	**$26**	**$31**

The current version of SAP will no longer be supported by the vendor beyond 2027. While Manitoba Hydro was criticized by Interveners about including costs for SAP S/4HANA, which Manitoba Hydro is considering for the replacement for SAP ECC, it would have been imprudent to not include costs for the current SAP replacement as work on this needs to start in the Test Years.

While Interveners have also criticized Manitoba Hydro through the hearing that a business case has not been provided for the SAP replacement,[318] it must be restated as it was many times through the proceedings that Manitoba Hydro needs the time to develop the business case and cannot provide a "work in progress" business case. Manitoba Hydro is ensuring that a thorough evaluation is conducted, which includes stage gates for approval through the process to replace SAP ECC:

[317] Coalition/MH I-76, part b.
[318] Transcript June 2, page 2907.

"MR. SVEN HOMBACH: So -- so Manitoba Hydro is currently at phase zero of -- of the business case, trying to determine what to do post-2027?

MR. ALASTAIR FOGG: That's correct. We're currently in the business case stage around SAP S/4 to determine whether it proceeds." [319]

Manitoba Hydro was directed by the PUB to file a 20-year Financial Forecast Scenario with this Application and certain assumptions had to be made on costs several years out in the future. Manitoba Hydro made a reasonable assumption on replacement or external support costs (which will be evaluated as part of the business case) based on the best information available at the time. As a result, Manitoba Hydro disagrees with Mr. Madsen's recommendation that "[a]ll costs be denied until a full business case is completed."[320]

14.6.1. Manitoba Hydro was Clear that an Increase in O&A Expenses Associated with Cloud Computing is not going to be Completely Offset with Decreases in Capital

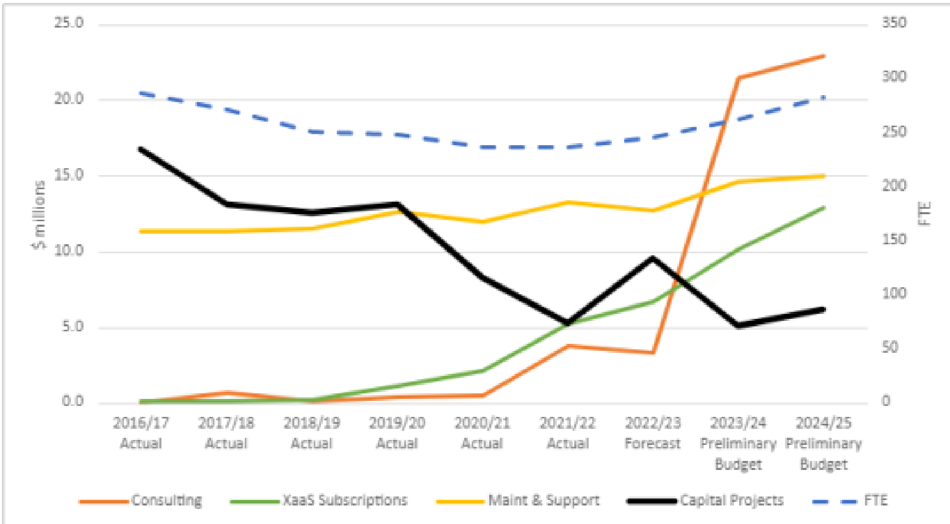
As discussed in Section 6.6.2 of Tab 6 of the Application and in the response to GSS-GSM/MH-II-6c, the shift in cloud computing costs are not directly linked. In other words, a dollar increase in O&A will not equate to a dollar decrease in capital as illustrated in the figure below.

[319] Transcript May 29, page 2177.

[320] GSS-GSM-7, Dustin Madsen, Emrydia Consulting Corporation Direct Evidence Presentation, June 2, 2023, slide 25.

Figure 30[321]

Figure 6.20 Digital and Technology Related Expenditures and FTEs



Existing computer hardware and software will have to be maintained, which is reflected as the Maintenance and Support line in the figure above. Over time, costs will decrease significantly as current systems reach end of life or are no longer supported and are replaced with cloud technology. Until then, these costs will remain and a slight increase is projected in maintaining Manitoba Hydro's current systems.

With the shift to the cloud, there are increased subscription costs, identified in the figure above as XaaS subscriptions. These are the costs paid to vendors for cloud-based arrangements. These costs started to increase with the rise of remote work and cloud-based services realized through the pandemic. As the shift to cloud continues, these costs will grow before existing legacy systems are retired.

Consulting costs include services to provide insight into new technologies and to provide expertise for new digital skills that Manitoba Hydro does not have in its internal resources. The changes in the digital environment have been significant and Manitoba Hydro's Information Technology group was shrinking. The current resources were required to maintain existing systems and continue with work as usual. Through the Business Model Review undertaken with a third party, new skills were identified that need to be filled, in addition to upskilling and reskilling current

[321] MH-1, Application Tab 6, Figure 6.20, page 34.

staff, and it has taken time to get the right structure into place. Through this change, the use of consulting services has provided an avenue to grow and build processes and plans. Consulting costs will continue to grow with the implementation of the SAP ECC replacement.

Mr. Madsen appeared to disregard this section of the Application as he stated in his direct evidence that capital should decrease at the same amount O&A is increasing for digital and technology.[322]

14.7. Manitoba Hydro has a Culture of Continuous Evaluation and Improvement

As stated in Tab 6 of the Application, Manitoba Hydro is focusing on continuous evaluation and process improvement to encourage the containment of costs and make improvements in the way employees work.[323]

Mr. Rainkie talked about how utilities need be more productive and stop doing things that may no longer be necessary:

> *"So I think the top-down portion of Manitoba Hydro's operating budgeting is missing because I think there's two (2) things missing in that equation, you know, the last year plus four (4) factors. And that is productivity savings. We're investing a lot in IT, as you see in the material.*
>
> *And why do people get merit increases? Because they go up in their -- not just because they've been at Manitoba Hydro for twenty (20) or thirty (30) years, they're more productive. There should be an expectation as people get those merit increases that there's some offset for -- on behalf of customers, some balance.*
>
> *The other thing is reprioritization, you know, through stop doing. So if there is energy transition and other strategic issues coming up, presumably -- you know, that are here, presumably something's coming off the bottom, right?*

[322] Transcript June 2, 2023, page 2899.
[323] MH-1, Application Tab 6, pages 4-5.

Like, you know, it might have been a great program ten (10) years ago, but if you've got all these things staring you in the -- in the face coming up, then something comes off the back. Most companies try to fund strategic initiatives through finding cuts in other areas that are of now low risk because there's bigger risks coming forward." [324]

This is precisely the culture that Manitoba Hydro is promoting through continuous evaluation and improvement. Manitoba Hydro is always looking at how to do things better, or whether it needs to continue to do things it has been doing. An example of this is tree trimming technology (as described in Tab 6 of the Application).[325] While it has saved a significant amount of hours at a minimal cost, this does not mean that Manitoba Hydro no longer needs the employees that would be called on to previously attend to these calls. Instead, those employees can spend time catching up on maintenance work or attending to other work that is required.

Manitoba Hydro has many examples of small productivity gains that are being done throughout the company. Business cases are not required to demonstrate the obvious benefits that result from small improvements. Manitoba Hydro is empowering staff to look at continuous evaluation on an ongoing basis. Recent examples of this were provided in Appendix 2.4 of the Application.

Following the VDP and pandemic, the extensive business model review is indicating where Manitoba Hydro needs to build up staffing levels to ensure it has the right people in the right place. Manitoba Hydro is rebuilding predominantly to deal with attrition, and accommodate the ever increasing work demands, while continuing to foster a culture of continuous evaluation and improvement.

To be clear, any increased productivity or efficiency is more likely to result in deferring the need for more FTEs versus FTE reductions. Manitoba Hydro's O&A associated with FTEs will not decrease because of continuous improvement, rather it has and will continue to facilitate the ability to complete more work with the FTEs its has today and those it is planning to add, to meet customers' needs while still maintaining the 15% reduction post VDP in the test years.

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[324] Transcript June 1, 2023, pages 2613-2614.
[325] MH-1, Application Tab 6, pages 8-9; COALITION/MH I-69, page 2.

14.8. Manitoba Hydro has a Rigorous Top-down and Bottom-up Approach to O&A Budgeting and Reporting

Manitoba Hydro has provided evidence in its Application, and during the hearing. about the level of detail that goes into the bottom-up detailed budgeting process.326

Mr. Madsen made claims about Manitoba Hydro's budgeting processes that are not factual and are not in line with evidence provided by Manitoba Hydro, including:

> *"Simplified forecasting practices likely create inaccurate forecasts that are difficult to manage to."* [327]

> *"What is not tracked is not managed and what is not managed is not tracked."* [328]

Manitoba Hydro does not have a simplified budgeting process, nor is it conducted at a high level. Manitoba Hydro leverages top-down and bottom-up budgeting to validate that plans are in place to meet the needs of the business while keeping the financial health and impact on customers in focus at an enterprise level.

As outlined in GSS/GSM-II-4a, Manitoba Hydro develops budgets for its 400 resource cost centers from the bottom-up. This includes budgeting:

- over 5,000 positions annually, some of which are seasonal staff and require appropriate cost flowing based on when they will be hired and paid;
- how each of these positions will use their time between capital, operating and non-chargeable time; and
- costs for each cost category based on need specific to each position and group, including employee related expenditures (overtime, benefits, meals, per diems, accommodations, motor vehicles, fuel, safety, training office expenses) and other costs related to consultants, contracted services, and all other cost categories

[326] MH-1, Application Tab 6, Section 6.2; GSS/GSM-II-4a-e; GSS/GSM-II-3a-c; GSS/GSM-II-4a; MH-42, MH Revenue Requirement Presentation.
327 GSS-GSM-7, Dustin Madsen, Emrydia Consulting Corporation Direct Evidence Presentation, June 2, 2023, slide 10.
328 GSS-GSM-7, Dustin Madsen, Emrydia Consulting Corporation Direct Evidence Presentation, June 2, 2023, slide 13.

included in Manitoba Hydro's O&A reports.

Once completed, the cost center budgets are rolled up to a department level, divisional level, business unit level and ultimately corporate level. The budgets are also approved at each of these levels as part of the budget review process. Manitoba Hydro's total O&A budget is then approved each year by the Manitoba Hydro-Electric Board and the Manitoba Treasury Board.

As outlined in PUB/MH-II-25a, Manitoba Hydro prepares a significant amount of reporting to monitor and control O&A costs on a monthly and quarterly basis. Attachments 1 and 2 of that information request include examples of such reports.

Monitoring and reporting are conducted at the department, division, business unit and corporate levels, consistent with how budgets are prepared, on a monthly and quarterly basis. Each quarter, reporting is also provided to the Manitoba Hydro-Electric Board and the Manitoba Treasury Board with explanations on significant variances and forecasts for the remainder of the fiscal year.

Manitoba Hydro also provides O&A quarterly reporting to the PUB for its information, as per Directive 14 of Board Order 73/15. The most recent quarterly report for the period ending December 31, 2022 was provided in the response to PUB/MH-I-74bU as Attachment 1.

As evidenced above, Manitoba Hydro is tracking and managing its costs in a very rigorous manner. As such, Mr. Madsen's suggestion that Manitoba Hydro is not tracking its costs and as such will have difficulties in controlling them[329] is entirely inconsistent with Manitoba Hydro's evidence and is simply incorrect.

14.9. Formal Zero-Based Budgeting is Not Recommended by Manitoba Hydro

Mr. Madsen has recommended that Manitoba Hydro should adopt zero-based budgeting to get better forecasts and be able to report and control costs in a more effective manner. Manitoba Hydro does not support this recommendation for the following reasons:

[329] Transcript June 2, 2023, page 2985.

- Manitoba Hydro does not see the value in doing formal zero-based budgeting based on the significant level of detail that is already developed in the budgeting processes as summarized above.
- As identified by Mr. Madsen, there is an "increased level of effort and cost to implement" zero-based budgeting.[330]
- Additionally, as a consequence of the organizational changes that Manitoba Hydro has encountered in the last several years, Manitoba Hydro has already utilized many of the same principles Mr. Madsen identified as benefits of applying a zero-based budgeting process including:
  - review of resource requirements based on the completion of the major capital projects and those assets now being in-service and resulting in increased O&A costs;
  - the Voluntary Departure Program and the rebuild that is happening through the Business Model Review to ensure having the right people in the right place in line with the new organizational structure, including a gradual rebuild from the hiring freeze in place in 2020/21 in support of the provincial government's cost savings initiative through the pandemic; and
  - consideration of resources needed based on being behind on necessary maintenance activities that ensure reliability and responsiveness to customer's needs.

Ms. Grewal indicated that although Manitoba Hydro may not conduct zero-based budgeting in a formal sense, it achieves the same thing as all costs are rigorously questioned and challenged when budgeting:

> *"MS. JAY GREWAL: I think, you know, there's varying views on what is zero-based budgeting. In my view, what is zero-based budgeting, you question and challenge every dollar you spend and, if that is zero-based budgeting, we do that in those costs that we control, and we actually ask our employees that for every dollar that we spend, you're making a decision to spend, can we -- if a customer asked us why we're doing it, tie it back to*

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[330] GSS-GSM-7, Dustin Madsen, Emrydia Consulting Corporation Direct Evidence Presentation, June 2, 2023, slide 13.

their interests, tie it back to reliability, tie it back to maintaining the system, tie it back to their service levels." [331]

MR. THOMAS REIMER: Do you believe that there would be any benefit to Manitoba Hydro to employ a zero-based budget strategy?

MS. JAY GREWAL: Here is what I would say, which is when we developed Strategy 2040, we re - we looked at how we are structured. We looked at the business model. People, process, technology and data. And when we did that, we went back to a zero-based approach in terms of what is every role, what is the function it performs relative to our mandate and what we're required to do. So, we did do that from a people perspective." [332]

MR. THOMAS REIMER: So, Ms. Grewal, my question was: Would there be benefits to Manitoba Hydro to employ a zero-based budgeting strategy?

MS. JAY GREWAL: In my view, we implicitly do zero-based budgeting through various processes by questioning every single dollar, but I wouldn't say a -- our budgeting exercise and processes are quite rigorous, whether that is zero-based in the traditional sense, it is in the intent of to question every dollar that we spend, and to make sure that we can speak to it and defend it in processes like we are in right now."[333]

Mr. Madsen acknowledged that Crown corporations have sophisticated budgeting processes, which may not follow the formal zero-based budgeting process which is essentially just "a concept". Manitoba Hydro agrees with Mr. Madsen on this point. Manitoba Hydro utilizes sophisticated budgeting processes in line with what Mr. Madsen described:

"MR. SVEN HOMBACH: Are you -- are you aware as to whether any Canadian Crown or vertically integrated utility has used a formal zero-based budgeting approach?

[331] Transcript May 15, 2023, page 315.
[332] Transcript May 15, 2023, page 321.
[333] Transcript May 15, 2023, page 322.

MR. DUSTIN MADSEN: Formal? That's a good question. So the sophistication of budgeting process for some of the Crowns is -- is quite -- as I understand it quite significant, quite sophisticated.

Do they -- do they call it a zero-based budgeting approach? I'm not sure, but the sophistication does vary, as I understand it, from entity to entity. Zero-based budgeting is -- maybe to be of assistance, it's -- it's a concept. It's -- the concept, as -- as I noted, that's both intended to assist with forecasting and tracking costs. So, an entity can be using and implementing the principles of zero-based budgeting, or many of them, without even intending to because it's essentially a description of best practices for how you would manage your business and forecast your efforts, if that's helpful. So I can't strictly say whether one (1) of the Crown utilities is using it or not, but I understand there is some sophistication." [334]

Mr. Madsen referred to utilities that do not use zero-based budgeting and how they escalate previous year's costs as follows:

"MR. DUSTIN MADSEN: Prove your costs. Don't just simply come in and say, last year they were $10 million, I've applied 2 percent, and now I need 10 million plus 2 percent." [335]

To be clear, Manitoba Hydro has never stated that the 2023/24 budget was simply the previous year's budget with a blanket percentage increase added. In Coalition/MH-I-66d, Manitoba Hydro stated that it took a top-down and bottom-up approach to developing the O&A budget for 2022/23 and the Test Years. The bottom-up detailed budgeting process performed was based on a recently reorganized structure and had significant change in costs to reflect new and changing business requirements. This includes, but is not limited to, costs related to returning back to full operations following the COVID-19 pandemic, and costs associated with new business initiatives such as the Integrated Resource Plan development and asset management work.

Budgets are based on the best information available at the time they are developed (i.e.

[334] Transcript June 2, 2023, pages 2986-2987.
[335] Transcript June 2, 2023, page 2986.

Summer 2022 for the 2023/24 and 2024/25 fiscal years). In Coalition/MH-I-66d, Manitoba Hydro further stated that it did not simply apply an escalator from 2023/24 to derive the 2024/25 O&A budget; in certain categories, there were no increases included from 2023/24 to 2024/25. As has been discussed extensively through the hearing and agreed to by many parties, the further out the forecast, the harder it is to get precision.

15. DEPRECIATION & REGULATORY DEFERRALS

Depreciation Issues

In its Application, Manitoba Hydro requested that the PUB accept an International Financial Reporting Standards ("IFRS") compliant depreciation methodology for rate setting purposes and has proposed use of the Equal Life Group ("ELG") Procedure applied on a straight-line basis using the whole life technique. Subsequent to Manitoba Hydro's application, in Order 42/23 the PUB identified six depreciation policy issues and requested that interested parties arrange for pre-hearing discussions between their respective depreciation experts to find common ground and narrow the areas of disagreement. These six issues were discussed through a series of Depreciation Technical Conference meetings with the expert witnesses representing Manitoba Hydro, MIPUG, Coalition, and GSS/GSM (collectively "the Parties"), resulting in the "Depreciation Issues Document",[336] which includes an analysis of the impact of depreciation methodology changes on customer rates. Based on those discussions, Manitoba Hydro is requesting the following from the Board:

- Approval of the use of an IFRS-compliant depreciation methodology for rate setting purposes to resolve the outstanding depreciation issues:
    - Manitoba Hydro recommends the ELG depreciation procedure applied on a whole life basis for rate setting purposes.
    - Manitoba Hydro considers the ALG depreciation procedure applied on a whole life basis to also be viable though not preferred as additional componentization would be required.
- Approval to cease additions to the Change in depreciation method deferral account for rate setting purposes subject to the Board's acceptance of an IFRS-compliant depreciation methodology for rate setting purposes.
- Direction with respect to continued deferral of gains and losses to the Loss on retirement or disposal of assets deferral account:
    - Should the Board accept use of the ELG procedure for rate setting purposes,

[336] PUB-20, Depreciation Issues Document.

Manitoba Hydro is indifferent as to whether the deferral of interim gains and losses is continued.

    - Should the Board direct Manitoba Hydro to use the ALG procedure for rate setting purposes, Manitoba Hydro supports the ongoing deferral of interim gains and losses.
    - Regardless of the depreciation procedure accepted for rate setting purposes, Manitoba Hydro recommends continuing the deferral of terminal losses to smooth the net income impact of future terminal losses.
- Approval to begin amortizing the Change in depreciation method and the Loss on retirement or disposal of assets deferral accounts.
- Approval for the establishment and amortization of a new regulatory deferral account to phase-in the application of IFRS depreciation for rate setting purposes subject to the Boards acceptance of ELG.
    - Should the Board direct Manitoba Hydro to use ALG depreciation procedure for rate setting purposes, it is recommended that any decision regarding the phase-in deferral account be tabled for review at the next general rate application.

<u>Other Regulatory Deferral Requests</u>

Manitoba Hydro also requests that the Board opine on the following regulatory deferral requests:

- Endorsement of the ***Keeyask In-Service deferral*** account and approval of an amortization period of 106 years.
- Determination of an amortization period for the ***Major Capital Projects deferral*** account. Manitoba Hydro has proposed amortization on a straight-line basis over a period of 2 years effective April 1, 2025.
- Write-off of the ***DSM Deferral*** debit and credit accounts, consistent with PUB Order 161/19 Directive 7 for Centra Gas. There is no impact to forecast net income associated with the write-off.

<u>SAP S/4HANA Regulatory Deferral Request</u>

Manitoba Hydro requests the Board opine on the following new regulatory deferral account:

- Pre-approval for the establishment of a regulatory deferral account to record the annual O&A expenses of costs related to the potential implementation of ***SAP S/4*** Cloud Computing Arrangement ("CCA") and to amortize the deferred balance for rate setting purposes over a period of 10 years subsequent to the actual in-service date.

15.1. The Board now has Sufficient Information to Opine on Depreciation Matters

Manitoba Hydro requests that the Board opine on the depreciation methodology to be used for rate setting purposes to resolve this long-standing issue.

In Order 43/13, the Board found it was unable to opine on the depreciation methodology for rate-setting purposes as not enough information had been provided to date to assess the true impact on ratepayers of a switch to ELG.

Manitoba Hydro submits that the information now on the record is sufficient to allow the Board to make a determination on the depreciation issues. The information placed on the record in this proceeding has demonstrated how the potential treatment of the depreciation issues would impact customers and that the alternatives recommended for the Board's consideration do not negatively impact customers. Any alternative that defers full resolution of the depreciation issues, including Alternative 3 and Alternative 4, as presented in Depreciation Issues Document, should be rejected.

Mr. Bowman and Mr. Madsen both indicate that extensive information has been provided on the record.[337] By recommending one of the two alternatives which allow for full resolution of the depreciation matters,[338] Mr. Bowman and Mr. Madsen have indicated that they believe the depreciation matters can be resolved during this proceeding.[339] In contrast, Mr. Rainkie is the only party who has indicated that a Board decision should be deferred to a future proceeding on the basis that Manitoba Hydro has not met the requirements of the outstanding depreciation Directives.[340]

As the PUB is aware, the Coalition chose not to produce Mr. Rainkie to provide any oral testimony during the concurrent panel on depreciation matters. Consequently, the parties to the proceeding were not afforded the opportunity to directly test Mr. Rainkie's recommendations. As such, Mr. Rainkie's recommendations to simply defer this matter further should be dismissed outright, or alternatively afforded no, or little weight, by the PUB when deliberating upon this matter.

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[337] Transcript June 5, 2023, page 3090; GSS-GSM-8, Dustin Madsen Depreciation Presentation, slide 4.
[338] Transcript June 5, 2023, page 3090; PUB-20, Depreciation Issues Document, page 32.
[339] PUB-20, Depreciation Issues Document, page 4.
[340] PUB-20, Depreciation Issues Document, page 33.

Furthermore, as indicated by Dr. Williams, the Coalition has not adopted the position of Mr. Rainkie:

> *"DR. BYRON WILLIAMS: Thank you. And I'll -- I'll just reiterate that the -- the position articulated by Mr. Rainkie may be different from the position -- it's not the position of the Coalition."* [341]

15.2. Examination of the Depreciation Policy Issues

As documented in the Depreciation Issues Document, there was broad consensus amongst all parties on the majority of the depreciation policy issues and the following findings were made:

<u>Policy Issue 1 - The use of an IFRS-compliant depreciation methodology for rate-setting purposes</u>

It is preferable for Manitoba Hydro to apply the same IFRS-compliant depreciation methodology for financial reporting and rate setting purposes to the extent possible, assuming it results in just and reasonable rates for customers. This removes the need to maintain separate accounts for financial reporting versus rate-setting and improves the comparability and understandability of the financial statements. Manitoba Hydro is the only utility known to use an IFRS-compliant depreciation methodology for financial reporting purposes and a previous CGAAP methodology for rate setting purposes.[342]

<u>Policy Issue 2 – ALG vs. ELG</u>

The Parties agreed that both the ELG and ALG procedures are rational and systematic approaches to determine depreciation, and both are acceptable under IFRS.

<u>Policy Issue 3 – The use of the remaining life or whole life technique</u>

Manitoba Hydro has used the whole life technique for depreciation rate calculations since the 2005 Depreciation Study. All Parties recommend continued use of the whole life methodology.

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[341] Transcript June 5, 2023, page 3031.
[342] PUB/MH I-118 part c.

Policy Issue 4 – Componentization

The Parties agreed that professional judgement is required to determine the appropriate level of componentization, and that it is the responsibility of management to exercise this judgement. Additionally, it was agreed that componentization review is an ongoing requirement and Manitoba Hydro should, and will, continue to review componentization, based on materiality, as part of each depreciation study, regardless of which depreciation procedure is selected by the Board.

Policy Issue 5 – The treatment of interim gains and losses

The Parties agreed that for financial reporting purposes, IFRS requires the recognition of gains and losses in net income. Regardless of the depreciation procedure used, the calculation of gains and losses to be reported for financial purposes requires estimation and professional judgement and is the responsibility of management.

Policy Issue 6 – The establishment and disposition of deferral accounts

All Parties agreed that IFRS 14 requires the establishment of amortization periods for all regulatory deferral accounts, and that for depreciation related deferral accounts, use of an amortization period reflecting the remaining life of the assets contributing to the accounts is reasonable for rate setting purposes. Manitoba Hydro's proposal to amortize depreciation related deferral accounts over the weighted average life of the accounts contributing to the balance is in line with the consensus agreement from the Depreciation Technical Conference and ensures intergenerational equity by matching the recovery of these costs with the time period over which the related assets are providing benefit.

15.3. The Remaining Depreciation Issues Where there is not Agreement are Limited

The remaining depreciation issues where the Parties did not reach agreement are limited. The areas of disagreement are:

- Whether an IFRS-compliant ELG or ALG depreciation procedure is preferable for rate setting purposes.
    - The level of componentization required under an ALG methodology to meet IFRS compliance.
- The treatment of gains and losses

15.4. There are Two Viable Alternatives

Based on the areas of consensus as well as the limited areas of disagreement, Manitoba Hydro, MIPUG and GSS/GSM identified two combined approaches, as reflected in Figure 31 below, to address the identified depreciation issues as part of the current proceeding:[343]

Figure 31 - Viable Alternatives for Resolution of Depreciation Issues

Alternative 1 – IFRS ELG as presented in the Amended Financial Forecast	Alternative 2 – IFRS ALG
Cease gain & loss deferral and depreciation method deferral, amortize deferral balances and phase-in ELG depreciation	Convert to ALG following completion of a further review process as defined by the PUB*, continue gains and losses deferral, continue depreciation methodology deferral until ALG transition; commence amortization of deferral balances effective September 1, 2023

15.5. Manitoba Hydro Recommends Alternative 1 – ELG

Manitoba Hydro recommends that the Board accept Alternative 1 – ELG. Board acceptance of Alternative 1 would allow for full resolution of the depreciation policy issues immediately on receipt of an Order, with no impact to customers. Based on the analysis outlined in the Depreciation Issues Document (Section 8.1), since depreciation is a non-cash item, the difference in net income between Alternatives 1 and 2 is not material enough to impact Manitoba Hydro's proposed 2% rate path, the proposed differential rates by customer class or the achievement of the 70% debt ratio target by 2039/40.

Furthermore, as Manitoba Hydro's IT systems already reflect the use of ELG for financial reporting purposes, there would be no significant effort required to implement ELG for rate setting purposes. Manitoba Hydro would simply stop the current deferrals and commence amortization. These changes would not result in any significant increased administrative activities and would have no impact for staff involved in planning, estimating and accounting for capital projects.

[343] PUB-20, Depreciation Issues Document, page 24.

The use of ELG has also become much more prevalent in Canada,[344] and acceptance of ELG for rate-setting purposes would not cause Manitoba Hydro to be an outlier amongst other Canadian electric utilities.

Finally, although Alternative 1 assumes a phase-in of IFRS depreciation over 15 years with amortization over 30 years and does not include the deferral of gains and losses, Manitoba Hydro is open to different approaches such as modification to the term and/or amortization period for the phase-in and continuing the deferral of gains and losses, as discussed at page 28 of the Depreciation Issues Document.

15.6. Alternative 2 – IFRS ALG is Viable but Additional Componentization is Required

While Manitoba Hydro has recommended acceptance of ELG for rate setting purposes, the adoption of IFRS-compliant ALG is also a viable alternative which would allow for resolution of the depreciation policy issues. Manitoba Hydro would implement an IFRS-compliant ALG methodology for both financial reporting and for rate setting purposes, as discussed at page 23 of Appendix 4.3 (Amended) of the Application.

While viable, the implementation of IFRS-compliant ALG for financial reporting and rate setting purposes is expected to take several years to fully implement and would require additional administration efforts and costs for both the implementation and as part of ongoing operations. Although the additional costs are not expected to be material to Manitoba Hydro's overall revenue requirement, the implementation effort and ongoing requirement for capturing additional detail within asset accounting and capital projects would divert resources from Manitoba Hydro's priorities, reducing operational efficiencies without providing any incremental value for customers.

Alternative 2 does not include any provision for phase-in as the impacts to net income are lower than that experienced with implementation of ELG, but a phase-in may still be of value, should operational risks materialize in the first few years of the forecast.

[344] PUB/MH II-37.

15.6.1. Componentization to Apply IFRS-ALG

As noted in the Depreciation Issues Document, the Parties disagree on the level of componentization required to implement an IFRS-compliant ALG procedure. Manitoba Hydro reaffirms that the existing level of componentization is not sufficient to meet the requirements of IFRS.

Alliance Consulting Group ("Alliance"), an independent third-party consultant, completed an IFRS-compliant ALG deprecation study[345] for Manitoba Hydro. All Parties agree that Alliance's componentization recommendations include some immaterial components, and that further work is required to review and refine this recommended componentization prior to implementation of an IFRS-compliant ALG methodology. In addition, all Parties agree that it is the responsibility of management to determine the appropriate level of componentization to ensure IFRS compliance for financial reporting purposes, regardless of the depreciation procedure. Refinement to eliminate immaterial components will not significantly change the outcome of implementing an ALG methodology.

If the Board directs Manitoba Hydro to implement ALG for rate setting purposes based on componentization that Manitoba Hydro does not consider to be IFRS-compliant, there would continue to be a timing difference between depreciation for financial reporting and rate setting purposes and as such Manitoba Hydro would be unable to implement the directed change for financial reporting purposes. Based on IFRS 14, this timing difference would need to be captured in a regulatory deferral account with an amortization period established by the Board and, if componentization differs for financial reporting and rate setting purposes, it would no longer be practicable to calculate the difference in an Excel spreadsheet, as Manitoba Hydro currently does.[346] As such, Manitoba Hydro would also have to create and maintain two full sets of accounting records which will result in significantly higher implementation cost and additional ongoing effort than that discussed in PUB/MH I-115b.

[345] MH-1, Application Tab 9, Appendix 9.11, IFRS-Compliant ASL Methodology Depreciation Study.
[346] Transcript June 5, 2023, page 3057.

Manitoba Hydro's assessment of IAS 16 indicates that the current level of componentization is not sufficient for IFRS compliance with use of ALG. Ms. Hooper provided further details on this aspect:

> *"… it's Manitoba Hydro's opinion that the current level of componentization is not compliant with IFRS on an ALG basis. And that's -- there are -- there's too wide of a dispersion in some of those accounts to -- for the average of the -- the average service life of the account to be representative of the depreciation or of the useful life of the assets contained in the account. And that's what you're seeing in the IFRS compliant ASL depreciation study, where those accounts have been split up in order to narrow the dispersion on the accounts, such that, the average is representative or is reasonably representative of the life expectancies of the assets within each account, after sub-componentization."* [347]

Manitoba Hydro's position on the need for additional componentization is consistent with that of the consultants Manitoba Hydro engaged to analyze the implications of IFRS and with depreciation studies conducted subsequent to Manitoba Hydro's IFRS conversion, as discussed by Mr. Fogg:

> *"I mean I -- I just would like to -- that -- that -- this goes all the way, as I mentioned, back to that initial conversion to IFRS. So, we would have detailed review and study at that time, both by Concentric, but also KPMG at the time from a financial perspective and an interpretation of IR -- IFRS. As Ms Hooper mentioned, that has continued in further studies that Mr. – detailed studies, that Mr. Kennedy had done and also is what you see in the Alliance study that Mr. Watson has done as well, which is another detailed review from a depreciation perspective."* [348]

The recommendations and studies discussed by Mr. Fogg are described further below:

- The original componentization determination was made by the Corporation during the initial review of IFRS requirements prior to the 2012/13 and 2013/14

[347] Transcript June 5, 2023, page 3148.
[348] Transcript June 5, 2023, page 3149.

GRA, based on discussions with our IFRS accounting and depreciation consultants. The need for additional componentization under ALG was reiterated during the 2015/16 and 2016/17 GRA in Appendix 11.49 to that Application and with the testimony of Larry Kennedy, then of Gannett Fleming, during that proceeding.The 2019 Depreciation Study states on page 1-1 that:

> *"Concentric notes that the ALG accrual rates are not in accordance with IFRS and should only be used for regulatory reporting purposes in the circumstances of Manitoba Hydro."* [349]

This statement provides a clear indication that Mr. Kennedy continues to maintain the position that the current level of componentization does not meet the requirements of IFRS. Ms. Hooper also addressed this in her testimony:

> *"It is Mr. Kennedy's opinion that more componentization is required for an ALG approach and that is reflected in the record from past proceedings."* [350]

- Alliance was retained specifically to prepare an IFRS-compliant ASL Depreciation Study,[351] which further supports the need for additional componentization as this study recommends an increase of 410 components (Appendix 4.3 page 22).[352]
- The Alliance study has reduced the ALG versus ELG difference for 2022/23 from \$54 million[353] with current componentization to \$19 million[354] with Alliance proposed componentization applied on a whole life basis. Manitoba Hydro considers the \$35 million reduction in the ALG vs ELG difference in annual depreciation expense to be material and to strongly support the need for increased componentization.

As outlined below, Mr. Madsen's opinion that the current level of componentization would be sufficient is an outlier opinion which is contrary to the opinion of Manitoba Hydro and that of the experts Manitoba Hydro has consulted on this matter who have

[349] MH-1, Application Tab 10, MFR 95-Attachment, Concentric 2019 Depreciation Study, page 1-1.
[350] Transcript June 5, 2023, page 3149.
[351] MH-1, Application Tab 9, Appendix 9.1.1.
[352] MH-1, Application Tab 4, Appendix 4.3, page 22.
[353] PUB/MH I-81, parts a-e, Figure 1 versus Figure 2.
[354] PUB/MH I-129.

conducted detailed reviews and studies of Manitoba Hydro's Property, Plant and Equipment:

- Mr. Madsen has proposed reliance on componentization from a depreciation study which the author (Mr. Kennedy of Concentric) explicitly describes as not compliant with IFRS.
- Mr. Madsen has not conducted a depreciation study for Manitoba Hydro that would inform his opinion on the required level of componentization for an IFRS-compliant ALG methodology and has limited experience with many of Manitoba Hydro's assets. Additionally, Mr. Madsen confirmed during oral testimony that he has never completed a depreciation study for a large, vertically integrated electric utility comparable to Manitoba Hydro:

  > *"MR. BRENT CZARNECKI: And so, in your experience since you've become a Certified Depreciation Professional, like Mr. Bowman, have you - - can you confirm that you haven't conducted a large scale depreciation study or evaluation of a large electric utility or even gas or oil company for that matter?*
  >
  > *MR. DUSTIN MADSEN: I've never been invited to. So, no, I have not."* [355]

- Further, Mr. Madsen appears to be basing his assessment of IFRS requirements entirely on paragraph 16.43 of International Accounting Standard ("IAS") 16 Property, plant and equipment,[356] and ignores the related interpretive paragraphs 16.44 to 16.47. Paragraph 16.46 indicates that items which are not individually material may be combined for purposes of determining depreciation expense, but if an entity has varying expectations for the useful life of the included items, approximation techniques may be necessary to ensure that depreciation faithfully represent the useful life of the included assets. This is a critical consideration when contrasting the level of componentization required for an ALG methodology vs. an ELG methodology:
  - Due to the averaging approach taken by the ALG method, depreciation expense will only reflect the useful life of the included assets if the range of service lives for the included items is relatively narrow.

[355] Transcript June 5, 2023, pages 3269-3270.
[356] PUB-19-5, Board Counsel Book of Documents, Volume 5 – Depreciation, page 10.

- In contrast, the determination of an ELG depreciation rate incorporates the expected service lives of each included equal life group within an account. As such the ELG procedure ensures that depreciation expense is reflective of the individual items within a group, provided that the assigned depreciation parameters are reflective of the range of expected service for the included items.

Based on the above, Mr. Madsen's opinion regarding Manitoba Hydro's componentization should be given less weight than the opinions of Manitoba Hydro and the expert consultants engaged by it that have conducted detailed depreciation studies and analysis of Manitoba Hydro's Property, Plant & Equipment. In addition, all Parties agree that Manitoba Hydro should continue to review its componentization as part of future depreciation studies, regardless of whether a change to an ALG procedure is made. Any changes to componentization should be based on significance/materiality.

15.7. Gains and Losses on the Retirement of Assets Should be Deferred

The Parties agree that IFRS 14 permits the deferral of gains and losses for rate setting purposes. Mr. Bowman and Mr. Madsen recommend the deferral and amortization of any interim gains and losses reported for financial purposes. As discussed by Ms. Hooper,[357] Manitoba Hydro's position on the treatment of gains & losses is specific to the alternative selected for resolution of the depreciation issues, as follows:

- Manitoba Hydro's preferred alternative, Alternative 1 – ELG, does not include deferral of gains and losses on the basis that annual amounts are estimated to be immaterial. However, there is still a possibility of larger losses occurring from time to time, and **Manitoba Hydro is not opposed to deferral and amortization.**
- Should the PUB decide in preference of Alternative 2 – ALG, **Manitoba Hydro supports the deferral of gains and losses**. Under ALG, annual losses are expected to be much more material and immediate recognition produces a fluctuating pattern of expense which is not reflective of the assets in service (Appendix 9.12 Section 1.3, Figures 10, 13 and 16).

While the Parties do not agree with the calculation method applied by Manitoba Hydro

[357] Transcript June 5, 2023, pages 3044-3045.

to determine gains and losses, the calculation method is irrelevant for rate setting purposes if gains and losses are deferred and amortized over the remaining life of the accounts giving rise to the balances. This was addressed by Mr. Fogg as follows:

> *"I'm -- I'm certainly not maybe as much of an expert as some of my colleagues over here in this respect, but maybe to simplify it, I think what we're saying is we are dealing with an issue around a group -- a group approach and dealing with something like interim gains and losses versus some of our interpretation of IFRS. As we noted in the depreciation issues document, that's really why we're saying that that deferral of -- of interim gains and losses may be a mechanism to address that both from that group approach perspective, as well as from the IFRS perspective of meeting both of those objectives, of being able to basically amortize those -- those over the average -- average life of the assets contributing to that -- that balance. So, it really would address all of the concerns that we're talking about if -- if we were to adopt an approach like that."* [358]

A change to the calculation of gains and losses would result in a shift between the gain/loss deferral account and accumulated depreciation, impacting the accumulated depreciation variance position of each account. Accumulated depreciation variances are amortized over the remaining life of each account through the true-up adjustment to depreciation rates. As such, if the amortization period for the gain/loss deferral account is based on the remaining life of the accounts giving rise to the balance, an equivalent amount is included in revenue requirement regardless of the gain/loss calculation approach used by Manitoba Hydro.

<u>Interim Gains & Losses versus Terminal Losses</u>

Under Alternative 1, Manitoba Hydro would be open to continued deferral of interim gains & losses (i.e., gains & losses pertaining to continuing operations, including cost of removal which is not eligible for capitalization) and has also recommended such a deferral as part of Alternative 2. The ongoing deferral of interim gains and losses is supported by all intervenors. Deferral of interim gains and losses over the weighted average remaining life of the accounts giving rise to the balance would provide a logical approach to the

[358] Transcript June 5, 2023, page 3169.

treatment of interim gains and losses.

Terminal losses (i.e., discontinued operations such as Selkirk Generating Station including related cost of removal) should be given specific consideration. This was addressed by both Ms. Hooper and Mr. Madsen:

> *"MS. MICHELLE HOOPER: "In our opinion, the -- the two (2) should be considered separately, and a decision should be made for what to do with interim losses and also what to do with terminal losses for rate-setting purposes. So for terminal losses, there is potentially some benefit to deferral in order to avoid spikes in in net income that may result when such a loss occurs.*
>
> *MR. DUSTIN MADSEN: "So -- it's Mr. Madsen. I -- I suppose it's -- from an accounting perspective, IFRS doesn't distinguish between whether the loss is terminal or interim, the -- simply that all gains or losses as quantified are -- are taken to income. I think the Board should assess whether or not, from a rate-setting perspective, it would be reasonable to defer all amounts. In other jurisdictions, the general practice for group assets is to defer interim. It's kind of de facto. It's the kind of approach that's used -- for rate-setting purposes, it's the approach that's used. Terminal losses have and -- and can be deferred. In some cases, they are simply recognized. So a terminal loss, for example, on a generating facility or a building may simply just be recognized in the year it is -- it occurs from a rate-setting perspective. It's just judgment of the Board as far as what's applied, but there's no bright-line test or-- or clear rule."*[359]

Terminal losses resulting from discontinued operations do not provide any enduring benefit to customers. However, these costs can have a significant impact and deferring them can smooth the impact to net income and the resulting impact to customers. A decision to write-off terminal losses would create precedence and future terminal losses would be subject to the same treatment for rate setting purposes. For example, the future costs to decommission and remove the Brandon Unit 5 (coal) and Selkirk generating

[359] Transcript June 5, 2023, page 3165.

stations would be subject to the same treatment and are expected to be significant.

15.8. Board approval is Required to Address the Treatment of Regulatory Deferral Accounts

15.8.1. Change in Depreciation Method Deferral Account – Cease Additions and Commence Amortization

Manitoba Hydro recommends cessation of the deferral account upon implementation of an IFRS-compliant depreciation methodology for rate setting purposes and amortizing the balance in the account into income based on the weighted average probable remaining life of the assets contributing to the accounts as discussed at pages 31-32 of Appendix 4.3 (Amended).

The timing of cessation of the deferral account is dependent on the methodology approved by the Board:

- Should the PUB approve ELG, the deferral would cease on receipt of an Order, assumed to be September 1, 2023 for forecast purposes.
- Should the PUB approve an IFRS-compliant ALG, the deferral would continue until implementation, which is not expected to occur until at least April 1, 2026.

Regardless of the Board's decision with respect to cessation of this deferral, Manitoba Hydro recommends commencing amortization of the existing balance in the account upon receipt of the Order based on the weighted average probable remaining life of the assets contributing to the accounts as discussed in Appendix 4.3 Amended (page 31). Intervenors support the need for amortization periods and agree that amortization should be based on the remaining life of the accounts giving rise to the balance.[360]

[360] PUB-20, Depreciation Issues Document, page 10.

15.8.2. Loss on Retirement or Disposal of Assets Deferral Account – Continue Deferral and Commence Amortization

The existing balance consists of both interim gains and losses (continuing operations) and terminal losses (discontinued operations).

Regardless of the depreciation procedure approved by the Board, Manitoba Hydro recommends commencing amortization of the existing balance in the account upon receipt of the Order based on the weighted average probable remaining life of the assets contributing to the accounts as discussed in Appendix 4.3 Amended (page 32). Interveners support the need for amortization periods and agree that amortization should be based on the remaining life of the accounts giving rise to the balance.[361]

There is merit to continuing the deferral of interim gains and losses, including the cost of removal on continuing operations, due to the enduring benefit to customers and deferring terminal losses including the cost of removal on discontinued operations to smooth the impact on net income. Although Manitoba Hydro's preferred Alternative (ELG) includes ceasing additions to the Loss on retirement or disposal of assets deferral account, Manitoba Hydro is not opposed to continuation of the deferral with ELG, as there is still a possibility of larger losses occurring from time to time.

15.8.3. New IFRS Depreciation Phase-in Deferral Account

As discussed in Section 15.5 and 15.6 above, Manitoba Hydro recommends Board approval of a new regulatory deferral account to phase-in the application of IFRS depreciation for rate setting purposes, subject to the Boards acceptance of ELG. Should the Board approve a phase-in deferral account Manitoba Hydro recommends commencing amortization with receipt of the Order.

Should the Board direct Manitoba Hydro to use an IFRS-compliant ALG depreciation procedure for rate setting purposes, it is recommended that any decision regarding the phase-in deferral account be tabled for review at the next general rate application.

[361] PUB-20, Depreciation Issues Document, page 10.

15.8.4. Keeyask In-service Deferral Account – Endorsement and Establishment of an Amortization Period

Manitoba Hydro recommends Board endorsement of the Keeyask in-service deferral and establishment of an amortization period. Manitoba Hydro has proposed an amortization period of 106 years which represents the weighted average service life of the Keeyask assets installed as at March 31, 2022, as discussed at pages 9-11 of Appendix 4.3 (Amended). Interveners did not dispute the proposed treatment recommended by Manitoba Hydro. However, Manitoba Hydro is open to alternative amortization periods as directed by the Board.

15.8.5. Major Capital Deferral Account – Establishment of an Amortization Period

Manitoba Hydro recommends an amortization period of two years which is comparable to the timeframe over which the revenues were collected from customers as discussed in Appendix 4.3 Amended (pages 32 to 33). Manitoba Hydro is open to other amortization periods as directed by the PUB.

15.8.6. Demand Side Management Deferral Accounts – Write Off the Existing Balances

Manitoba Hydro is seeking PUB approval to write off the offsetting accrued balances in the Demand Side Management deferral accounts as discussed in Appendix 4.3 Amended (pages 33-34). This recommended approach is consistent with the PUB Order 161/19 Directive 7 for Centra Gas. The write-off of the offsetting balances has no impact to Manitoba Hydro's revenue requirement and as such will have no impact to customers. Intervenors have not disputed the proposed write-off of these accounts.

15.9. SAP S/4HANA and the Proposed SAP Regulatory Deferral Account

Manitoba Hydro is currently in Phase 0 (pre-planning) of the replacement of its existing SAP ECC system, which will produce a readiness assessment and business case for SAP S/4HANA. While Manitoba Hydro considers it likely that it will proceed with SAP S/4HANA, a full business case is required to fully support a decision to proceed with SAP S/4HANA which will most likely be a cloud-based solution. Although the business case for the SAP replacement is not yet complete, Manitoba Hydro is requesting pre-approval for a regulatory deferral account to provide a mechanism to defer and amortize the significant one-time costs of a potential cloud-based application, as discussed in Appendix 4.3 Amended (pages 11-13). Manitoba Hydro recommends an amortization period of 10 years which is reflective of the expected service life.

Manitoba Hydro anticipates the replacement of SAP to be a cloud-based solution. Based on interpretation of the accounting standards, implementation of a new cloud-based system would be captured as operating and administrative expenses for financial reporting purposes, instead of capitalization to an intangible asset as for traditional on-premise information technology systems. Manitoba Hydro has not recommended the deferral of small cloud-based systems, due to immateriality.

Establishment of a regulatory deferral for the implementation of SAP S/4HANA with an approved amortization period would ensure the costs are treated consistently for rate setting purposes irrespective of whether the business case recommends an on-premise or cloud-based solution. Since Manitoba Hydro does not have past precedence for any information technology related deferral accounts, this request requires the Board's approval prior to the establishment of a deferral account. This was address by Mr. Fogg:

> *“MR. SVEN HOMBACH: So, if the Board were to defer a decision on whether or not to approve these accounts, would Manitoba Hydro be able to set them up, for lack of a better word, on a spec, like it has done with the depreciation accounts?*
>
> *MR. ALASTAIR FOGG: Mr. Hombach, I think our -- our assessment of that, at this point in time, is with something like SAP S/4 as it's -- as it's new and requires the Board's approval, our -- our initial analysis would be that -- that we wouldn't be able to create this with -- without that -- that direction at this time. If it was indicated that it – they were -- the Board were deferring that decision to a later date, but not outright rejecting it, I suppose that would put us in a bit of a grey area of trying to consider how*

to -- how to treat that in that interim time period if we were still incurring those costs.” [362]

Mr. Rainkie claimed that “There is PUB precedent for a RDA Based on an Accounting Change Related to Centra Meter Exchange Costs (Order 152/19).” [363]

Cloud computing arrangements are new technology for which the accounting treatment is based on interpretation of existing standards, rather than a change in accounting standards. While the Centra meter exchange costs were subject to a change in accounting treatment upon implementation of IFRS, this is not the case for cloud computing arrangements, and as such the Centra meter exchange regulatory deferral account is not an appropriate or reasonably comparable precedent for the proposed SAP S/4HANA regulatory deferral.

Mr. Madsen recommends the deferral of all cloud-based computing costs rather than limiting the deferral to major systems. Mr. Madsen also recommends deferring all costs related to SAP S/4HANA including the costs to evaluate the alternatives:

“... Deferral account treatment should be approved in principle, for all potential solutions, including the status quo, transition to a new on premise system or adoption of SAP S/4HANA, if that is ultimately the course of action. And I also would accept that some of the Phase 0 costs, which are, essentially, the costs to evaluate alternatives, should be included as actuals, within the deferrals, and reviewed at a later date." [364]

Manitoba Hydro's recommended deferral includes information technology costs that would have traditionally been capitalized but are no longer eligible for capitalization due to the shift to cloud-based services and technologies. As such, the recommended deferral does not include Phase 0 (pre-planning) costs, which are not eligible for capitalization to an intangible asset under IAS 38. Manitoba Hydro recommends continuing to expense Phase 0 costs, for consistency in treatment of the evaluation of information technology system alternatives for rate setting purposes, regardless of whether the systems are

[362] Transcript May 29, 20203, pages 2186-2187.
[363] CC-20, Darren Rainkie Direct Evidence Presentation, June 1, 2023, slide 54.
[364] Transcript June 5, 2023, page 2908.

traditional on-premise or cloud-based solutions.

As indicated by Mr. Fogg, deferring the implementation costs for the new SAP replacement, if the solution is cloud based, would ensure consistent treatment with that for a capital project:

> *"The business case for SAP S/4 is still in development and, as such, a decision to fully proceed with its implementation has not been made at this time. However, based on the age of the current SAP system and there being no support going forward, the cost associated with anticipated implementation of SAP S/4 were included in the long term forecast to ensure an accurate representation of potential future costs. Since the new SAP is also anticipated to be cloud based, it has been captured as an operating and administrative expenses instead of capital like the existing version of SAP would have been recorded. Establishment of a regulatory deferral for SAP S/4 would ensure the costs are still treated as if it were a capital project."* [365]

Manitoba Hydro's proposal to defer implementation costs for the SAP S/4HANA regulatory deferral account is consistent with the treatment directed by BCUC in Order Number G-85-23 in the matter of the British Columbia Hydro and Power Authority Application for Approval of Cloud Costs Regulatory Account:

> *"1. BC Hydro is approved to establish the Cloud Costs Regulatory Account effective fiscal 2023, attracting interest at BC Hydro's weighted average cost of debt to:*
>
> *a. Defer, on an ongoing basis, the forecast Cloud Arrangement implementation operating costs and the variance between forecast and actual Cloud Arrangement implementation operating costs that would have been capitalized for each project had the Cloud Arrangement been eligible for capitalization as an intangible asset."* [366]

[365] Transcript May 29, 2023, page 2032.
[366] GSS-GSM-10, Undertaking #48 response, page 2.

Should the Board conclude that costs for all cloud-based solutions should be deferred, Manitoba Hydro recommends that deferral should apply only to costs which would be eligible for capitalization for traditional on-premise information technology systems and should exclude costs which are not eligible for capitalization under the IAS 38 Intangible Assets, such as research and business case analysis, to ensure consistency in treatment for rate setting purposes.

15.10. Manitoba Hydro Does Not Support P. Bowman Recommendation #4

In his written evidence, Mr. Bowman has recommended a modification to the amortization period for the following items to be one year, with the intent that the full amortization occur in the 2022/23 fiscal year:

- Conawapa planning costs ($316 million)
- Selkirk and other GS loss on retirement ($43 million)
- Removal costs for assets that were not replaced ($23 million)

It should also be noted that a decision to change the amortization period to one year for the affected deferrals is likely to be considered a non-adjusting subsequent event to Manitoba Hydro's fiscal year ended March 31, 2023, based on IAS10. This means the 2022/23 financial statements would not be adjusted and amortization of the remaining balance would be reflected in the 2023/24 financial statements, as discussed in Manitoba Hydro's Apr 21, 2023, letter in response to his recommendation.[367]

15.10.1. Manitoba Hydro Does Not Support Change in Treatment of the Conawapa Deferral Account

Manitoba Hydro does not support the recommendation to modify the amortization period on the Conawapa deferral account to one year. There is no anticipated benefit to customers as a write-off of the Conawapa deferral account is not anticipated to improve or change the achievement of the debt ratio targets or affect the proposed 2% rate path. Additionally, a decision to change the amortization period on the Conawapa deferral account could create precedence for the treatment of other deferral accounts and create uncertainty around the valuation and future recovery of

[367] MH-22, Manitoba Hydro letter re: P. Bowman Recommendation #4, April 21, 2023, page 2.

all regulatory deferral accounts. This uncertainty exists in relation to both current accounting standards as well as the new IFRS Exposure Draft (ED) on Regulatory Assets and Liabilities. This is discussed further in Manitoba Hydro's April 21, 2023 letter in response to Mr. Bowman's recommendation.[368]

15.10.2. Manitoba Hydro Does Not Support Change in Treatment of Terminal Losses Related to Selkirk and Brandon Unit 5 (Coal) Generating Stations

Manitoba Hydro does not support the recommendation to modify the amortization period for terminal losses (discontinued operations) which forms part of the existing Loss on retirement or disposal of assets deferral account. As discussed in Section 15.7 above, terminal losses can cause deterioration in net income if significant, and the continued deferral of costs related to discontinued operations likely still has merit from a rate smoothing perspective. Manitoba Hydro recommends amortization of the existing $43 million terminal loss account over time, to smooth net income for regulatory purposes, and to establish precedence for treatment of future terminal losses including costs to decommission and remove assets.

Manitoba Hydro submits that the deferral of terminal losses (discontinued operations) for Selkirk and Brandon 5 (coal) generating stations should remain in-place with a Board established amortization period as discussed in Section 15.8.2 above and should not be amortized to net income over one year as recommended by Mr. Bowman.

15.10.3. Manitoba Hydro Does Not Support Change in Treatment of Accumulated Cost of Removal Pertaining to Continuing Operations

Manitoba Hydro does not support the recommendation to modify the amortization period on the accumulated of cost of removal which forms part of the existing Loss on retirement or disposal of assets deferral account. This cost of removal balance reflects the accumulation of cost of removal for interim retirements to remove individual assets within continuing depreciation accounts, where replacement is physically distant from the original asset, and as such the cost of removal cannot be capitalized

[368] MH-22, Manitoba Hydro letter re: P. Bowman Recommendation #4, April 21, 2023, page 2.

as a site preparation cost for the new asset. This cost of removal has traditionally been included as part of the measurement of gains and losses and has been partially funded through the inclusion of a net negative salvage factor in depreciation rates prior to the implementation of IFRS. The pre-collected portion of this cost of removal forms part of Manitoba Hydro's accumulated depreciation variance, which is amortized into net income over time through a true-up adjustment to depreciation rates. As such, amortization of the accumulated cost of removal over the weighted average remaining life of accounts contributing to the balance as recommended by Manitoba Hydro serves to recognize these costs into net income over the same period of time as the associated pre-collection.

Additionally, should the Board accept Mr. Bowman's recommendation to modify the amortization period for the accumulated cost of removal, precedent would be set which would apply to future such costs of removal pertaining to continuing depreciation accounts for Manitoba Hydro. A further complication on this issue relates to Centra Gas Manitoba Inc. ("Centra"), as subsidiaries normally follow accounting practices of the parent entity, and regulatory principles should be applied consistently to both entities. The annual cost of removal on continuing operations is not material to Manitoba Hydro but is very material to Centra. Accelerating the amortization period to one year for accumulated balances (approximately $7 million) and ongoing annual charges (approximately $2 million per year)[369] would have a very material impact on the financial statements of Centra.

Manitoba Hydro submits that cost of removal on continuing operations should remain in-place with a Board established amortization period as discussed in Section 15.8.2 above and should not be amortized to net income over one year as recommended by Mr. Bowman.

[369] MH-22, Manitoba Hydro letter re: P. Bowman Recommendation #4, April 21, 2023, page 7.

15.11. Other Depreciation Matters

15.11.1. The Parameters Included in the 2019 Depreciation Study are Reasonable and Should be Accepted by the Board

Manitoba Hydro recommends that the Board accept the 2019 Depreciation Study[370] including Concentric's recommended service life and Iowa curve assumptions. The depreciation parameters included in the 2019 Depreciation Study were accepted and approved by Manitoba Hydro Management prior to implementation.

Estimation of depreciation parameters (service lives, Iowa curves and life span dates) requires professional judgement and is the responsibility of Management.

Manitoba Hydro engages a consultant (a Certified Depreciation Professional) to provide recommendations with respect to depreciation parameters. The Board has traditionally accepted past depreciation studies without modification of parameters identified for individual accounts. As indicated on page 3-3 of the 2019 Depreciation Study, Section 3.2.2 Survivor Curve Judgements, the determination of service life estimates does not rely wholly on actuarial analysis of historical retirements:

> *"The service life estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of historical retirement patterns, a review of management's plans, policies and outlook, a general knowledge of the electric industry, and comparisons of the service life estimates from our studies of other electric utilities."*

The 2019 Depreciation Study parameters were tested by MIPUG through a series of information requests. Concentric's recommendations are strongly supported in the responses to these information requests, providing solid justification for Board acceptance of the recommended parameters.[371]

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[370] MH-1, Application Tab 10, MFR 95-Attachment, Concentric 2019 Depreciation Study.
[371] MIPUG/MH I-55 parts g, i, j, k and m.

15.11.2. GSS/GSM Recommendations for Account 3200M Should be Dismissed

In his written evidence, Mr. Madsen, the expert witness for GSS/GSM recommends that the PUB either direct the existing life curve for account 3200M HVDC Synchronous Condensers and Unit Transformers to be maintained at 65-R4 or to make a more moderate and gradual adjustment to a 65-R3[372]), indicating that, in Mr. Madsen's opinion, there is insufficient justification for the change in parameters recommended by Concentric.

It should be noted that Mr. Madsen has never prepared a depreciation study for a large vertically integrated electric utility,[373] and as such has limited experience with the HVDC equipment included in this account.

Considering the relative inexperience of Mr. Madsen compared to Concentric with respect to this specific equipment, Mr. Madsen's opinion regarding the depreciation parameters for account 3200M should be given less weight than that of Concentric, and Mr. Madsen's recommendations for this account should be dismissed.

15.11.3. Manitoba Hydro's Current Approach for Management of Accumulated Depreciation Variances is Reasonable

Manitoba Hydro's asset base is currently in an over-depreciated position due largely to life extensions and to the removal of the net negative salvage from depreciation rates per Directive 8 of Order 75/15, as shown in the response toa Manitoba Hydro undertaking.[374] The current practice of Manitoba Hydro is to include a provision for the true-up of accumulated depreciation variances over the remaining life of each depreciation account in the depreciation rates developed as part of each depreciation study.

As indicated in the following transcript references, although the absolute amount of the current variance is a large number, when taken in context of Manitoba Hydro's asset base, the balance is not overly concerning and all witnesses testifying on this

[372] GSS-GSM-5, Written Intervener Evidence – Dustin Madsen, April 3, 2023, page 62.
[373] Transcript June 5, 2023, page 3270.
[374] MH-52, Undertaking accepted at Transcript Page 3194, page 18.

matter concur that it is reasonable to continue the current practice of amortizing this variance over the remaining life of the accounts:

> *"MS. MICHELLE HOOPER: My understanding is this is the most widely used meth -- like approach that's applied to recovering accumulated depreciation variances is to allocate, like, to recover them over the remaining life of the accounts."* [375]

> *"MR. DUSTIN MADSEN: ...I would recommend you continue to amortize that balance over the expected remaining life of the assets."* [376]

> *"MR. PATRICK BOWMAN: You know, it doesn't take much of a swing in some of your big accounts to see those numbers vary. It looks big as a billion dollars, but as Mr. Madsen says, it's like 5 percent of your assets. So, I -- I just say, on that front, yeah, remaining life is -- is vastly the most common approach even if it's done through a whole life estimate and then amortized the remaining life, or done as a remaining life method."* [377]

> *"[MR. DANE WATSON]: I -- I totally agree. The -- the most common method is remaining life. And -- and so that would be over the -- equal to what you're doing in the whole life approach by taking the remaining life to carry that across. And I have seen negatives of this nitro swing to positives and then back to negatives. So, you need to be careful about you're looking at a theoretical reserve. And the theoretical reserve is based on a number of parameters. So, you've got to be careful not to make a -- a quick, sort of -- a quick reaction to something. And you also, I think, need to ask if it was a positive instead of a negative, would you be recovering it over five (5) years, and to make sure you're not biassing because of which direction it is."* [378]

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[375] Transcript June 5, 2023, page 3194.
[376] Transcript June 5, 2023, page 3085.
[377] Transcript June 5, 2023, pages 3200-3201.
[378] Transcript June 5, 2023, page 3201. Note the transcript incorrectly attributed the above testimony of Mr. Dane Watson to Mr. Dustin Madsen.

> *"MR. PATRICK BOWMAN: But as - - as Mr. Watson noted, you know, in relation to the size of the asset base, these are actually fairly small numbers. So I wouldn't read too much into it until one, sort of, notes the pattern and sees -- and see if it is sustained for long periods. Either way, I think it would be a fairly -- it would be a fairly high hurdle to say that you'd want to do something other than take these balances and amortize them over the remaining life."* [379]

16. DEBT MANAGEMENT

Access to the Province of Manitoba's high credit quality has allowed Manitoba Hydro to achieve its debt management objective: to provide stable, low-cost funding to meet the financial obligations and liquidity needs of the corporation, while maintaining risks at prudent levels and reserving sufficient flexibility to adapt to changing circumstances.

Over the last decade, consolidated gross debt grew to $25 billion at the peak. In order to reduce refinancing risk, Manitoba Hydro favored longer dated debt maturities that enhanced debt stability by extending the debt portfolio's weighted average term to maturity to the current 19.1 years. Manitoba Hydro also took advantage of the low interest rate environment to decrease the debt portfolio's weighted average interest rate to the historically low 3.4%.[380]

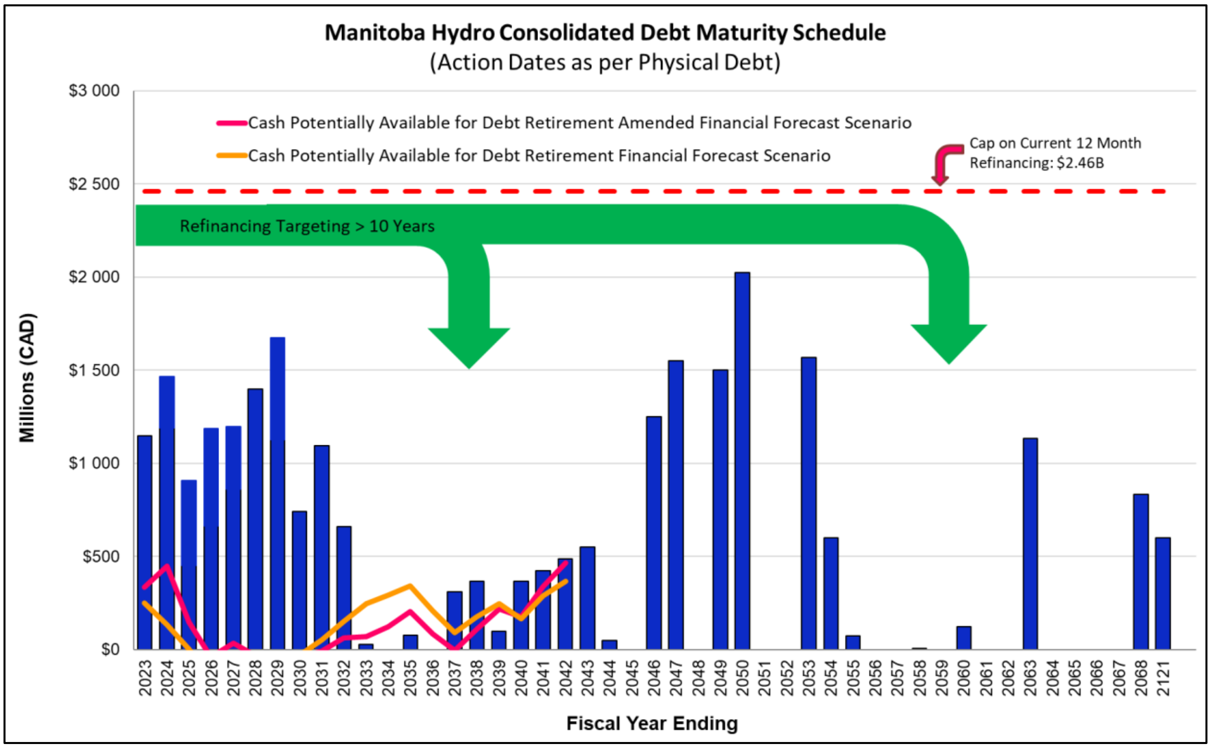
During this time, the interest rate risk was reduced by decreasing the percentage of floating rate debt within the debt portfolio. With nearly $1.5 billion of debt maturing in fiscal year 2024/25, Manitoba Hydro has approximately 6% of the gross debt portfolio maturing in this 12-month period. With 1% floating rate debt in the current debt portfolio, the total Interest Rate Risk Profile potentially subject to interest rate risk at March 31, 2023 is 7%.[381]

The following figure depicts Manitoba Hydro's debt maturity schedule at September 30, 2022. The green arrows reflect the expected terming of the anticipated refinancings in the next decade into the debt maturity schedule. The cash potentially available for debt retirement under the Amended Financial Forecast Scenario (pink line) exceeds the cash

[379] Transcript June 5, 2023, page 3220.
[380] MH-42, MH Revenue Requirement Presentation, May 29, 2023, slide 35.
[381] Transcript May 29, 2023, page 2015.

available under the Financial Forecast Scenario (orange line) in the first decade allowing for accelerated repayment of debt and earlier achievement of financial targets.

Figure 32[382]



16.1. Recovery of Financial Resilience Necessary to Respond to Emerging Needs

Manitoba Hydro's total debt has more than tripled from 2005 to 2022 to fund the construction of new major capital and, as a result, has seen its financial metrics weaken as the debt has grown at a much faster pace than revenues. While this weakening is to be expected during a period of investment, there is an expectation that with the new assets now generating revenue, the utility should be able to improve its financial metrics.

The energy sector has seen unprecedented changes in recent years. The trends of decarbonization, digitalization and decentralization will continue to shape and disrupt Manitoba Hydro's business environment in the coming years. The pace and breadth of these changes are unpredictable, but the $10.8 billion of long-term debt which Manitoba

[382] MH-1, Application Tab 4, Appendix 4.5, Debt Management Strategy, page 1.

Hydro has maturing this decade is a known quantity.[383] With no external borrowing for new major capital on the horizon this decade, now is the time for recovery of Manitoba Hydro's financial health and financial metrics to proactively position the corporation as financially resilient to respond to the emerging needs and expectations of its customers.

Manitoba Hydro must be financially resilient to withstand disruptive events that impact revenues or expenses and continue to deliver on its mission. For Manitoba Hydro, financial resilience is directly related to a stronger balance sheet and is achieved by having sufficient liquidity, a prudent amount of leverage, and enough access to debt capacity to be able to plan for future investments with certainty and at low cost.

The following table summarizes the challenges, the impacts and the target metrics to address the challenges.

Figure 33[384]

Challenge	Impact	Target Metric
Liquidity	Solvency and stability	Cash on hand: 6 months cash requirements Sinking fund reserve: contribution = 1% of debt and 4% of sinking fund balances at previous fiscal year end
Debt Level	Interest Expense Level Financial Flexibility Contingent Liability to Province	Debt in Capital Structure Ratio: legislated targets 80% by 2035, 70% by 2040 Improve other metrics including Cash Flow/Debt
Interest Rate Environment	Interest Expense Volatility	Interest Rate Risk Profile: within policy and guideline limits target IRRP < 10% of debt portfolio
Borrowing Authority Limit	Access to low-cost debt financing	Temporary borrowing authority = $500 million New borrowing authority = new approved capital Remaining refunding authority = debt refinanced
Independent Assessment	Self-supporting Status	Credit Opinions from Moody's, DBRS and S&P affirming status

16.2. Interest Rate Risk is Pressuring Finance Expense

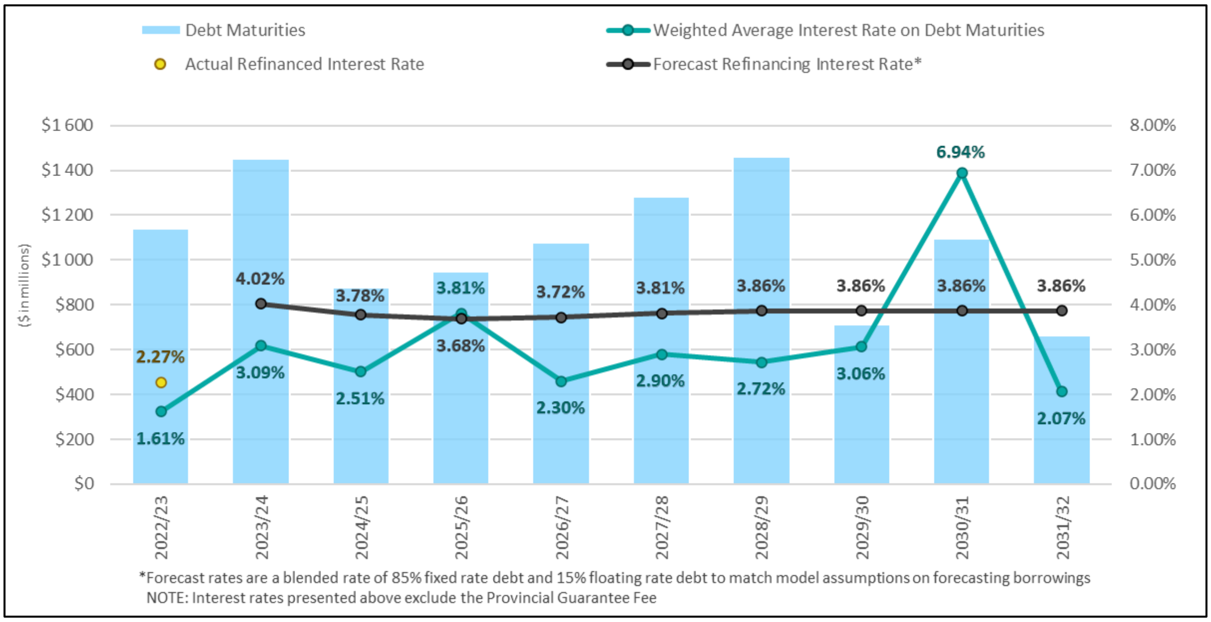
During the past decade, there was significant exposure to interest rate risk on new borrowings to fund capital investments. Though new borrowings have abated, Manitoba Hydro has, on average, $1.1 billion in debt maturities potentially requiring refinancing

[383] MH-1, Application Tab 4, Appendix 4.5, Debt Management Strategy, page 4.
[384] MH-42, MH Revenue Requirement Presentation, May 29, 2023, slide 38.

every year over the next decade.[385]

These debt maturities will place upward pressure on finance expense as maturing debt is currently projected to be refinanced at higher interest rates. Higher interest rates and the uncertain interest rate environment keep interest rate risk elevated for Manitoba Hydro. On June 7, 2023 the Bank of Canada raised the target overnight rate again by 0.25% to 4.75%. The Bank of Canada's key message was that "excess demand in the economy looks to be more persistent than anticipated" and there is growing risk that inflation "could get stuck materially above the 2% target."[386]

Figure 34[387] - Annual Debt Maturities, Underlying Debt Rates and Projected Re-financing Rates



Despite Mr. Rainkie's assertions that interest rate risk has decreased in comparison to forecasts at prior GRAs,388 Manitoba Hydro's exposure to interest rate risk has never been more elevated. Currently, Manitoba Hydro has high risk exposure as a result of both the level of debt which needs to be serviced and limited cash flow with which to service the debt, as evidenced by a weak cash flow to debt ratio.389 Further, Manitoba Hydro

[385] MH-1, Application Tab 4, Appendix 4.5 (Amended), Debt Management Strategy, page 1.
[386] Bank of Canada, June 7, 2023, online: Bank of Canada raises policy rate 25 basis points, continues quantitative tightening - Bank of Canada.
[387] MH-1, Application Tab 4, Appendix 4.5 (Amended), Debt Management Strategy, page 15.
[388] CC-7, Revenue Requirement Evidence prepared by Darren Rainkie, April 3, 2023, page 33.
[389] Transcript May 29, 2023, page 2025; MH-24, Rebuttal Evidence, page 56.

will have limited ability to request higher rate increases as a result of the new legislative framework coming into effect April 1, 2025. Limited rate increases reduce Manitoba Hydro's capacity to absorb interest rate risk volatility.

With limited financial flexibility, and a cash flow to debt ratio not expected to exceed 5% in the first decade of the Amended Financial Forecast,[390] Hydro will choose debt management strategies which limit the financial risks with respect to the debt portfolio.

16.2.1. Interest Rate Risk Profile

Manitoba Hydro will maintain the interest rate risk profile ("IRRP") which is the percentage of short-term debt, floating rate debt and debt maturing within 12 months, to below 10% of the debt portfolio to mitigate interest rate exposure and limit volatility to finance expense.

16.2.2. Peer Group Comparatives

As seen in the table below, the peer range for floating rate debt is 1%-19% which is very similar to the new Manitoba Hydro target guideline for floating rate debt of 0%-20%. Manitoba Hydro is not an outlier, Newfoundland and Labrador Hydro reported between 1%-3% floating rate debt in the reported periods, lower than Manitoba Hydro's 1%-5%.

[390] MH-24, Rebuttal Evidence, page 57.

Figure 35[391]

Peer Group Historical Floating Rate Debt %	2018	2019	2020	2021	2022
Manitoba Hydro	4%	5%	3%	1%	1%
BC Hydro	10%	13%	12%	11%	11%
SaskPower	17%	14%	13%	6%	11%
Hydro Quebec	9%	5%	7%	7%	6%
NB Power	17%	16%	13%	11%	16%
Nfld. & Labrador Hydro	2%	2%	3%	1%	n/a
Emera Inc.	14%	18%	18%	19%	n/a
Fortis Inc.	10%	13%	10%	9%	10%
Canadian Utilities Limited	11%	8%	8%	10%	n/a

Note: Floating Rate Debt = Long Term Floating Rate Debt + Short Term Debt
Sources: Annual Reports
n/a: Reports not yet available

16.2.3. Updated Independent National Bank Financial Analysis

Contrary to Mr. Rainkie's assertions, current and forecast interest rate risk profiles in the Amended Financial Forecast Scenario are not materially lower than the updated floating rate range from the National Bank Financial independent analysis model but at the lower boundary of the range of 8% - 15%. In the forecast years from 2023-2042, the annual interest rate risk profiles are forecast to be in the range of 5%-10% with an average of 8% over the 20-year timeframe.[392] Given Manitoba Hydro's risk context, the interest rate risk profile is not more averse than necessary.

Manitoba Hydro will also select debt maturities that minimize the addition to the refinancing schedule in the next decade and target to maintain a longer term weighted average term to maturity of the debt portfolio. Manitoba Hydro will manage the refinancing risk within the existing debt portfolio by continuing to smooth the debt maturity schedule.

16.3. Liquidity Risk

Liquidity risk is the risk of not having sufficient cash to meet financial obligations as they

[391] Coalition/MH II-25, part a.
[392] Coalition/MH I-144, pages 6-12.

come due. To mitigate this risk, Manitoba Hydro maintains targets for cash on hand and the sinking fund reserve. Cash on hand is expected to decrease as new cash requirements decrease while the availability of internally generated funds will allow Manitoba Hydro to replenish the sinking fund reserve.

16.4. Sinking Fund

Until recently, Section 41 of *The Manitoba Hydro Act* required Manitoba Hydro to make a minimum annual contribution to the sinking fund reserve equal to 1% of the debt outstanding at March 31 plus 4% of the sinking fund balance at March 31. The legislated contribution formula allowed the corporation to set aside internally generated funds to retire debt borrowed over a period of approximately 42 years.

1) Legislated Changes to the Sinking Fund

This long-standing section of *The Manitoba Hydro Act* was repealed in November 2022 but was replaced with other legislative provisions which provide for debt servicing costs to be included in revenue requirement.

Pursuant to section 15(1.1) of *The Manitoba Hydro Act,* Manitoba Hydro has the ability to create reserves and sinking funds when they are required. In section 39(1) of *The Manitoba Hydro Act,* the new definition of "revenue requirement" is:

> *"in relation to a rate period, means the amount of rate revenue required in each fiscal year within the rate period*
>
> *(a) to pay the reasonable costs forecast by the corporation for that fiscal year, including*
>
> *(i) the corporation's operating, maintenance and administrative expenses,*
>
> *(ii) amounts in respect of capital expenditures,*
>
> *(iii) debt service costs, and*
>
> *(iv) power purchases, taxes, fees and other amounts required to be paid out of the corporation's revenue; and*
>
> *(b) to achieve, in accordance with the regulations, the financial targets set out or referred to in subsection 39.1(1) and address material risks that could affect the achievement of those targets."*

Manitoba Hydro is currently in discussions with the Province of Manitoba to redefine the sinking fund and take the necessary steps to provide for the governance, if required.[393]

2) <u>History of Sinking Fund Use</u>

Manitoba Hydro has maintained sinking fund reserves throughout history. However, due to the capital expansion of the last decade, Manitoba Hydro was reinvesting all its earnings in assets to expand its core business, as well as borrowing unprecedented volumes of debt. In order to minimize the accumulation of gross debt, Manitoba Hydro began reducing the accumulated sinking fund balances with more frequent withdrawals, depleting the sinking fund reserve completely by 2016. Manitoba Hydro's cash flow projections at the time indicated that the corporation's investing activities would exceed cash from operations until at least 2022, and the utility would be sourcing the cash for sinking fund contributions from the issuance of debt – thereby incurring additional costs. At the time, in order to optimize the liquidity practices, minimize gross debt balances and to reduce finance expense, Manitoba Hydro sought to minimize sinking fund balances where feasible.

3) <u>Planned Use of the Sinking Fund</u>

With the new capital assets now in service, Manitoba Hydro targets to replenish the sinking fund reserve with cash from operations where possible to fund yearly debt retirement. As Manitoba Hydro has debt maturing every year this decade, in order to manage gross debt levels, the corporation intends to draw down the sinking fund reserve each year to repay maturing debt. Manitoba Hydro requires Cash from Operations to exceed Cash used for Investing activities in order to contribute earnings of the corporation, not borrowed funds to the sinking fund reserve.

On average, prior to the depletion of the sinking fund, Manitoba Hydro held investments equivalent to about $700 million in the reserve. Manitoba Hydro's peers all maintain sinking fund reserves, averaging between $200 million and $800 million over the last five fiscal year ends. The sinking fund reserve protects Manitoba Hydro against both liquidity risk and interest rate risk as it provides the utility with cash to repay debt maturity obligations each year.

[393] MH-52, Undertaking #41, pages 9-11.

4) Funding the Sinking Fund Reserve with Cash from Operations is Required

The ability to fund contributions to the reserve from internally generated funds conveys to the financial markets and credit rating agencies that the utility is reasonably servicing its debt and setting aside funds for the debt to eventually be repaid.

16.5. Debt Level

The elevated debt level is a challenge as it increases the level of interest expense which must be recovered through rates. Historically, prior to reduction in payments to government, 40% of Manitoba Hydro's revenue was used to pay interest costs; this has now been reduced to 30% of revenue.[394] Paying down debt now will help reduce interest costs in the near term for existing customers, as well as over the longer term.

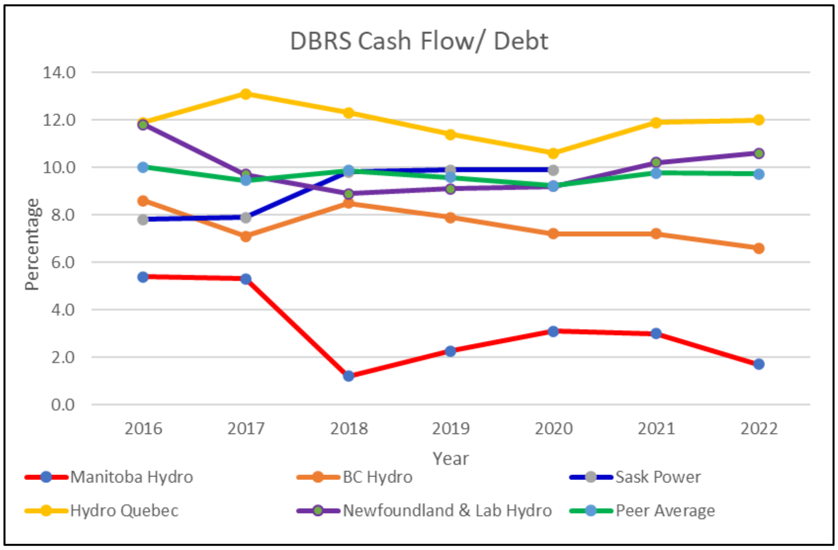
The debt level also impacts Hydro's financial flexibility and is a high contingent liability to the Province. To mitigate these impacts, Manitoba Hydro is targeting to improve its debt in the capital structure from the current 85% to meet the newly legislated targets.

16.5.1. Cash Flow to Debt Ratio

With weak financial metrics and debt levels as elevated as those of Manitoba Hydro's, the sinking fund reserve will mitigate the risk that a portion of the utility's debt be deemed to be not self-supported. Manitoba Hydro's peer utilities have an average cash flow to debt ratio of over 9% over the period 2016-2022 as indicated in the following graph.

[394] Transcript May 29, 2023, page 2020.

Figure 36[395]



The ratio is used to assess the amount of cash the utility has available to make interest and principal payments on debt. The higher the ratio is, the better position the company is in to meet its financial obligations. A declining or very low ratio means the business may not have enough available cash to make its principal and interest payments on debt.

As noted earlier, Manitoba Hydro's total debt more than tripled from 2005 to 2022 to fund new major capital. During this time Manitoba Hydro's Cash Flow to Debt ratio has decreased from ~9% (2005-2009) similar to peers, to approximately 2% (2018-2022) as rates collected from customers did not keep up with the debt growth.[396]

16.5.2. Peer Comparison of Financial Metrics

Mr. Colaiacovo's claims that Manitoba Hydro is unique and "you're really at a loss in looking for a peer group. You can look at all of these, but none is a perfect comparison."[397] Perfection is not necessarily a requirement for comparison. Credit rating agencies actively do reference Manitoba Hydro's peers for comparative purposes:

[395] MH-42, MH Revenue Requirement Presentation, May 29, 2023, slide 40.
[396] Transcript May 29, 2023, page 2025.
[397] Transcript June 6, 2023, page 3303.

> *"Given the company's weak financial profile and limited rate increases we may reassess our view of Manitoba Hydro's self-sufficiency…**These financial metrics are among the weakest, if not the weakest, of any of Manitoba Hydro's peers**, including vertically integrated provincially owned crown corporations in Canada." – Moody's report on Manitoba Hydro May 26, 2022."* [398] [**emphasis added**]

Currently, Manitoba Hydro has less financial flexibility as compared to most peers to respond to risks such as an increase its interest expense volatility.

16.6. Self Sufficiency

16.6.1. Independent Assessment

Credit rating agencies provide an independent assessment of financial health. Rating reports provide information to investors which aid them in their investment decisions and inform the interest rate levels at which investors will purchase Province of Manitoba bonds. Manitoba Hydro's target is to maintain the utility's self-supporting status.

16.6.2. Cash Flow Cost Coverage

DBRS, a credit rating agency which rates the Province of Manitoba and Manitoba Hydro, has published its criteria for attributes of a self-supporting Crown which include:

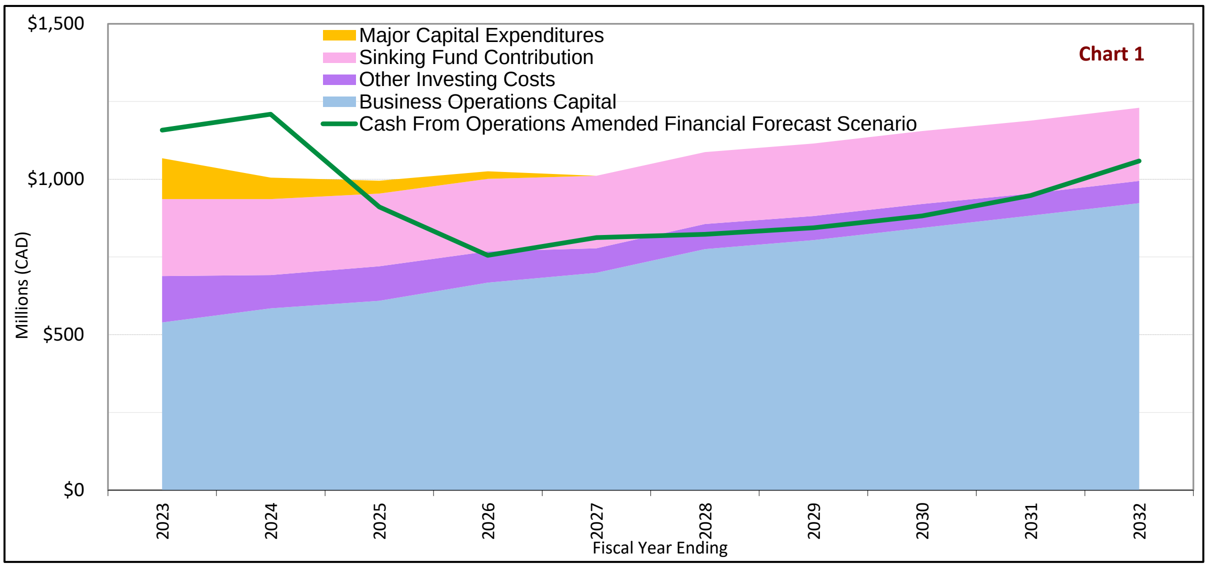
- The Crown is generally profitable and does not rely on material subsidies or supports from the provincial government;
- The Crown is generally able to meet its ongoing costs and maintenance capital expenditures through internally generated cash; and,
- Debt servicing costs will be met through the regular course of business or through a well-defined recovery mechanism (e.g., rates).

[398] MH-1, Application Tab 4, Appendix 4.5 (Amended), Debt Management Strategy, page 3.

To note, debt servicing costs are interest and principal payments on debt over a particular period of time. In Manitoba Hydro's case, *The Manitoba Hydro Act* formerly implied that timeframe was 42 years.

The figure below illustrates the coverage of costs with internally generated funds included in the Amended Financial Forecast Scenario.

Figure 37[399]



In order for the Corporation to remain self-supporting, Manitoba Hydro's cash from operations, the green line, should generally fund business operations capital shown in blue, other investing activities shown in purple and the sinking fund contribution shown here in pink.

The cash from operations in the Amended Financial Forecast Scenario is sufficient to fund these cash requirements in fiscal years 2023/24 through 2025/26. However, cash from operations drops dramatically in 2026 with a reduction in forecast export revenues, before starting to increase with the cumulative impact of 2% rate increases. Beginning in 2026, Manitoba Hydro would need to borrow to fund all or a part of the sinking fund contribution for the remainder of the decade. In the second decade,

[399] MH-42, MH Revenue Requirement Presentation, May 29, 2023, slide 41.

Manitoba Hydro would be able to begin replenishing the sinking fund with earnings from the corporation.

Mr. Colaiacovo understands that cash flow is important as he states "there is no dispute that cash flow is important. –[…] I think that if Manitoba Hydro was at risk of breaching a critical cash flow target, we would all agree that rates should rise as a result."[400]

While the 2% rate path may not provide 100% coverage of costs in the first decade, the trend shows that these costs will be met over the longer forecast horizon. Manitoba Hydro believes the 2% rate path can smooth rates to promote rate stability and predictability for customers and balance the financial integrity of the utility with the rate impacts on customers over the longer term while ensuring system reliability.

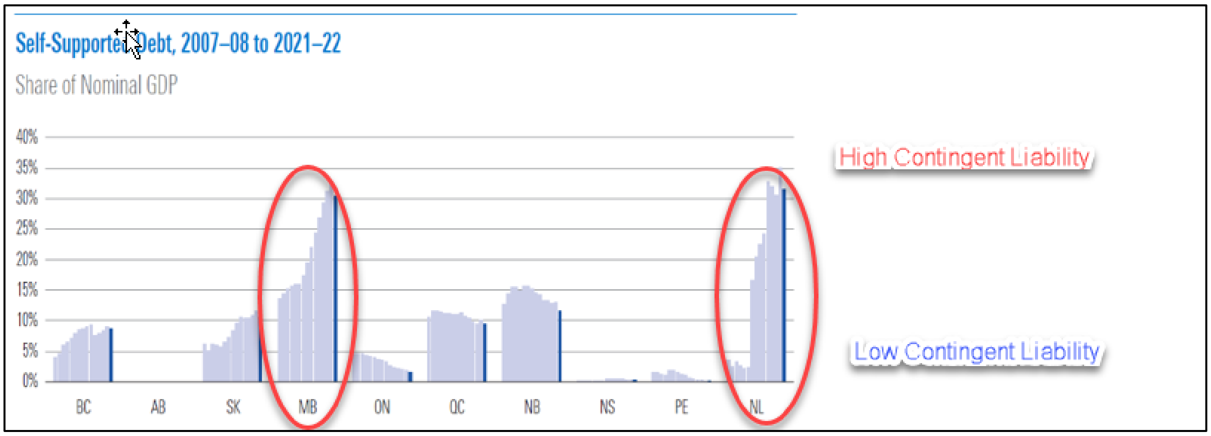
16.6.3. Contingent Liability to Province

As a Crown corporation, Manitoba Hydro's credit ratings are a flow-through of the Province's. Manitoba Hydro's financial health is an important factor for credit risk assessment of the Province. Credit analysts look at the trends of financial metrics as well as business risks of Manitoba Hydro in order to assess the status of Manitoba Hydro's debt. As long as Manitoba Hydro's debt is self-supporting, its debt load should not impact the Province of Manitoba's credit risk.

As seen in Figure 4.37 in Tab 4 of the Application and shown below, DBRS shows that Newfoundland and Manitoba have the distinction of having Government Business Enterprises with the highest debt relative to GDP of any province which means Manitoba Hydro and Newfoundland & Labrador Hydro represent the highest contingent liabilities to their respective provinces as compared to their peers.

[400] Transcript June 6, 2023, page 3319.

Figure 38[401]



Confirming this, Moody's comments on the Province of Manitoba's top credit challenge as being the elevated debt burden and contingent liability risk of Manitoba Hydro in its most recent July 7, 2022 Credit Opinion on the Province of Manitoba.[402]

If Manitoba Hydro's debt is not self-supported by revenues, it is considered tax-supported and does impact the Province of Manitoba's credit risk. Investors will decide how much compensation they need to buy and hold Province of Manitoba bonds based on the credit risks. The riskier the credit, the more compensation in form of a higher yield will be required.

Mr. Colaiacovo similarly described this:

> *"Especially now since Manitoba Hydro represents such a large portion of the Government of Manitoba's total bond portfolio, it's -- it's in the high 30 percent range now ,So the entire market knows that, you know, a very significant portion of Manitoba's issues are actually for Manitoba Hydro. And --* ***and there is attention paid to Manitoba Hydro's performance as a result of that because Manitoba's bonds are supported not just by taxes, but they're also -- those bonds, because they are on-lent to Manitoba Hydro, are supported by Manitoba Hydro revenues****. So -- so there is full understanding of that in the market. You're right, when they buy a bond issue, it does not have*

[401] MH-24, Rebuttal Evidence, page 55.
[402] MH-1, Application Tab 4, Appendix 4.6, pages 7-14.

> *Manitoba Hydro's name on it. But when they are doing their analysis of, you know, how much of this bond issue do we want to support and what price are we going to demand, what's the credit spread that we're looking for, you know, under -- under what Manitoba Hydro circumstances are they going to -- like what -- it's -- it's almost a theoretical question to say:* ***What -- if there were an announcement from Manitoba Hydro that caused you to change your view on the credit spread**, what would it be, right?"* [403] [**emphasis added**]

Manitoba Hydro notes its debt represents 44% at March 31, 2022, of the Government of Manitoba's total debt portfolio. [404]

Maintaining the Province's high credit quality is important to Manitoba Hydro and to the utility's customers as it allows the Corporation to secure attractive financing opportunities.

16.6.4. Retained Earnings Addressing Risks

Mr. Colaiacovo notes that "Retained earnings are going to increase by approximately $5 billion over the next 18 years, in order to try and achieve those debt-to-equity targets, the -- the debt ratio target."[405] Manitoba Hydro notes that this increase in retained earnings is largely related to the reduction in payments to government. Absent the reductions, with rate increases of 2% per annum for the 20-year forecast period, retained earnings would not grow by $5 billion.

The Province of Manitoba has made two decisions which impact how and when Manitoba Hydro will recover costs from customers due to material risks such as hydrology and interest rate risk:

1) Changing legislation: Under Section 39(1) of *The Manitoba Hydro Act*, the new definition of "Revenue Requirement" is "the amount of rate revenue required in each fiscal year within the rate period….(b) to achieve, in accordance with the regulations, the financial targets set out or referred to in subsection 39.1(1) and

[403] Transcript June 6, 2023, pages 3348-3349.
[404] MH-1, Application Tab 4, Appendix 4.5 (Amended), page 9.
[405] Transcript June 6, 2023, page 3332.

address material risks that could affect the achievement of those targets."

2) On November 23, 2022 reducing payments to government by 50% with direct savings for Manitoba Hydro of approximately $4 billion over the 20-year forecast period allowing Manitoba Hydro to lower rate increases to customers and model a 2% rate path for the long term forecast.

These actions allow for Manitoba Hydro to build retained earnings and financial resilience to withstand adverse events which impact to costs and revenues while providing rate predictability and stability for customers.

Mr. Colaiacovo recognizes there is a trade-off between addressing risks through retained earnings or through rates, stating "it's legitimate to consider how many different risks should be addressed by building up financial reserves, building up retained earnings over time, how -- and which kinds of risks should just be reflected in rate policy." [406]

16.7. Finance Expense Impacts of Variable Rate Debt

Borrowing authority limits impact Manitoba Hydro's access to low cost debt financing. *The Manitoba Hydro Act* was recently amended removing reference to an increased limit of $1.5 billion for temporary borrowing. As a result of this recent legislative amendment, a $500 million promissory note program remains in place as approved by a 1992 Order-in-Council which also approved the guarantee of the $500 million promissory note program.[407] The limit currently remains at $500 million which is the lowest limit for short-term borrowing of any of Manitoba Hydro peers.

16.7.1. Short Term Borrowing

Manitoba Hydro cannot increase its short-term borrowing in any significant manner or reasonably plan for its increase as suggested by Mr. Rainkie until such time as a provincially guaranteed short-term borrowing facility greater than $500 million is available. As such, any savings to finance expense that Mr. Rainkie has calculated

[406] Transcript June 6, 2023, page 3336.
[407] MH-24, Rebuttal Evidence, page 65.

based on increasing short-term borrowing levels are not available and overstated savings at this point in time.

16.7.2. Floating Rate Debt and Fixed Rate Debt of the Same Term are the Same Cost at Issuance

When asked by Board counsel on June 1, 2023 if he agreed that when debt is placed, floating rate debt and fixed rate debt of the same term have the same yields, Mr. Rainkie responded "No"[408] and then continued to indicate that:

> *"it's a very theoretical perspective, but like, the forecasts that are embedded in the rate application are based on consensus forecasts." … "Those institutions forecast fixed rates being higher than floating rates". Manitoba Hydro clarifies that the* ***institutions forecast short term rates and long term rates, not fixed and floating rates."***[409] [**emphasis added**]

As Manitoba Hydro indicated in information requests, at the time of actual issuance in the marketplace floating rate long-term debt is priced to be indifferent over the term of the bond as compared to fixed rate long-term debt <u>of the same term</u>.[410] With no differential between fixed and floating rate long-term debt in the marketplace at time of issuance, there are no cost savings to be realized. Assuming an upward sloping yield curve, issuing debt with a shorter term to maturity would have a lower interest cost. However, it is the <u>term to maturity differential that provides cost savings, not the variability of the interest rate</u>. Shorter termed debt will bear greater refinancing risk than longer term debt.

17. DISTRIBUTED GENERATION (SOLAR), NET BILLING & THE EXCESS ENERGY PRICE

In Order 59/18, the PUB issued Directive 7 which stated "Manitoba Hydro credit net-metered customers' excess energy put on the grid at the rate of 8.196¢/kWh for 2018/19. Manitoba Hydro must apply to the Board for approval of any future net-metered rate or changes to the 8.196¢/kWh rate." In Order 90/18, the PUB granted Manitoba Hydro's

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[408] Transcript June 1, page 2850.
[409] Transcript June 1, page 2850.
[410] Coalition/MH I-44, part l; Coalition/MH II-25, part e.

request to set aside Directive 7 of Order 59/18 and the PUB stated "[t]he issue of the Board's legal jurisdiction to approve the rates applied by Manitoba Hydro to credit customers for excess energy returned to the grid will be considered at the next General Rate Application."[411]

Before setting out Manitoba Hydro's position on the PUB's jurisdiction to set the price for excess energy returned to the grid, it is important to first provide an overview of the background and factual context.

17.1. Customers with Distributed Generation

Manitoba Hydro's customers may generate their own electricity for their home or business using alternative energy technologies such as solar and wind. This is called non-utility generation ("NUG") or distributed energy resources. These resources are installed behind-the-meter ("BTM") and customers may use the electricity their system generates to reduce the amount of electricity they purchase from Manitoba Hydro. In most situations, NUG resources must be connected to the Manitoba Hydro grid because a customer's system may not be able to produce electricity 24 hours a day, such as when the sun is not shining or the wind is not blowing.[412] If customers generate more energy than they are using, the excess energy can be sold back to Manitoba Hydro. As of October 4, 2022, there were 1,171 BTM distributed generation installations in Manitoba, 99% of which were solar.[413]

Depending on solar panel sizing, up to 60% of the solar energy produced by a residential system will be surplus to the residential needs and sold to Manitoba Hydro, while the other 40% is consumed by the residence. The self-generated solar energy displaces the energy that would, in the absence of solar panels, have been purchased from Manitoba Hydro. The Manitoba Hydro energy that would have been sold to the residential consumer is still available and is now sold on the export market.[414]

Solar energy is largely generated in the spring and summer months, when the Manitoba

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[411] PUB Order No. 90/18, pages 3-4.
[412] PUB 19-2, PUB Book of Documents, Volume 2, page 66.
[413] MH-1, Application Tab 9 (Amended), page 19; AMC/MH I-9a.
[414] MH-1, Application Tab 9 (Amended), page 20.

load is lower and Manitoba Hydro is already exporting surplus energy. Therefore, a very high proportion of the surplus solar energy ends up being exported by Manitoba Hydro to the MISO energy market as an opportunity sale.[415]

Bi-directional metering is installed for customers with distributed generation resources. These meters separately record the amount of electricity supplied by Manitoba Hydro to the customer, as well as how much excess energy is generated by the customer's installation and put onto the Manitoba Hydro grid.[416] A separate line item reflecting the value of any excess energy is presented on the customer's bill and netted from the overall amount owing to Manitoba Hydro for energy purchased by the customer from the grid.

17.2. Net Billing for Distributed Generation

Manitoba Hydro does not use or offer net metering to its customers. Net metering creates an energy credit (often applied in kWh) to draw on at a later date. Instead, as explained in pages 21-22 of Tab 9 (Amended) of the Application, Manitoba Hydro offers a net *billing* program.

Net billing allows customers to generate electricity for their own use and sell their excess electricity to Manitoba Hydro. Customers receive a monetary credit on their Manitoba Hydro account and the monetary credit is applied against other charges on their monthly bill. If a customer requires more electricity than their system generates, they will purchase that energy from Manitoba Hydro at the current applicable PUB-approved electricity rate, just like they did before they installed their system. When their system generates more electricity than they use, they will receive a monetary credit for their excess generation at the excess energy price.[417]

17.3. Excess Energy Price

As explained in PUB/MH I-43c (Updated) and PUB/MH II-18a-c, the excess energy price is calculated based on the previous year's actual export market energy prices and approximates the return that Manitoba Hydro can generate from selling the excess

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[415] MH-1, Application Tab 9 (Amended), page 21; Transcript May 17, 2023, page 768, lines 1-4.
[416] MH-1, Application Tab 9 (Amended), page 21.
[417] PUB/MH I-43f-j, page 3.

energy into the export market. The price is updated annually on April 1 and it can vary significantly depending on the market value. As explained by Mr. Gawne:

> *"Manitoba Hydro's use of this excess energy price is set based on the value that that wind, or pardon me, that solar is pushing back into our system. So, it's the -- it's the -- it's the process that Manitoba Hydro is setting. It's not the actual price. That's a product of the historic market clearing."* [418]

Historical pricing is used because it is a recent, actual value that is publicly available and transparent to customers. Excess energy production by solar photovoltaic systems occurs in the largest quantities in the summer when Manitoba Hydro already tends to be a strong exporter, which is why it is valued at recent MISO energy prices. Manitoba Hydro determined that this spot market price was best suited to value excess generation purchases, while also being a publicly available value.

The excess energy price is not directly comparable to Manitoba Hydro's marginal value of generation. The marginal value of supply includes an energy value plus capacity values for generation, transmission and distribution and is based on future price and cost projections. The marginal value of generation energy is also not used to calculate the excess energy price because it is a confidential value and would not be transparent to the end customer.

During cross-examination, Mr. Gawne was asked whether the Surplus Energy Program rates could be used for determining the price for solar.[419] While conceptually the rates approved for the Surplus Energy Program would provide a more timely price signal related to Manitoba Hydro's short-run marginal cost, Manitoba Hydro is of the view that the added complexity[420] associated with implementing similar pricing at this time is not warranted. Typically, the excess energy price will be less than the customer's applicable tariff rate and therefore, in most cases, customers with distributed generation will receive

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[418] Transcript May 17, 2023, page 769, lines 7-13.
[419] Transcript May 17, 2023, pages 770-772.
[420] Hourly metering data is currently not obtained from the existing bi-directionally metered customers on Manitoba Hydro's system but would be a requirement in order to use the time-varying aspect of the Surplus Energy Program rates. Additional meter reading and billing costs would be associated with the ongoing administration of such a pricing mechanism for the over 1,000 distributed generation customers compared to the thirty existing SEP customers.

the most benefit if they can consume their generator's output rather than export it to the Manitoba Hydro grid. As a result, the excess energy price does not generally act as a price signal beyond the point of initial investment and therefore the time lag associated with the current excess energy price is not a concern and not likely to be relevant to a customer's decision to consume power.

17.4. Jurisdiction

Manitoba Hydro's position on the PUB's jurisdiction has not changed since its May 30, 2018 Application to Review and Vary, and it repeats and relies on the legal argument set out in that filing.[421] It is still important to reiterate the key legislative provisions for the PUB's consideration.

The PUB's scope of authority is derived exclusively from the enacting legislation. In determining the PUB's jurisdiction to set rates, three pieces of legislation must be read together: *The Public Utilities Board Act*, *The Crown Corporations Governance and Accountability Act* (the "CCGAA") and *The Manitoba Hydro Act*.

In general terms, *The Public Utilities Board Act* section 2(5) states the PUB does not have jurisdiction or authority over Manitoba Hydro subject to certain specific exceptions. Part 4 of the CCGAA sets out the PUB's rate approval jurisdiction. While this section was recently amended by the Act and no longer references Manitoba Hydro, the transitional provisions state:

> ***Transitional***
> *65 Despite Part 1 and sections 23 and 64 of this Act, the following Acts or provisions, as they read immediately before the enactment of this Act, continue to apply to the determination of rates for the retail supply of power under* The Manitoba Hydro Act *for any period ending before April 1, 2025:*
> *(a) Part 4 of* The Crown Corporations Governance and Accountability Act*;*
> *(b)* The Manitoba Hydro Act*;*
> *(c) section 2 of The Public Utilities Board Act.*[422]

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[421] Manitoba Hydro Application to Review and Vary Order 59/18, Appendix B, pages 1-11.
[422] SM 2022, c 42.

Prior to being amended by the Act, the relevant parts of the CCGAA section 25 read as follows:

> ***Hydro and MPIC rates review***
> *25(1) Despite any other Act or law, rates for services provided by Manitoba Hydro and the Manitoba Public Insurance Corporation shall be reviewed by The Public Utilities Board* under The Public Utilities Board Act *and no change in rates for services shall be made and no new rates for services shall be introduced without the approval of The Public Utilities Board.*
>
> ***Definition: "rates for services"***
> *25(2) For the purposes of this Part, "rates for services" means*
> *(a) in the case of Manitoba Hydro, prices charged by that corporation with respect to the provision of power as defined in* The Manitoba Hydro Act*;*

The PUB has jurisdiction to approve rates for services provided by Manitoba Hydro, meaning the price charged by Manitoba Hydro for the provision of "power" which is defined in *The Manitoba Hydro Act* as "electrical power howsoever generated, and includes electrical energy."[423] *The Manitoba Hydro Act* sets out what is to be recovered in the price of power sold by Manitoba Hydro and confirms the PUB's rate approval authority at section 39:

> ***Price of power sold by corporation***
> *39(1) The prices payable for power supplied by the corporation shall be such as to return to it in full the cost to the corporation, of supplying the power, including*
> *(a) the necessary operating expenses of the corporation, including the cost of generating, purchasing, distributing, and supplying power and of operating, maintaining, repairing, and insuring the property and works of the corporation, and its costs of administration;*
> *(b) all interest and debt service charges payable by the corporation upon, or in respect of, money advanced to or borrowed by, and all*

[423] *The Manitoba Hydro Act*, C.C.S.M. c. H190, section 1.

obligations assumed by, or the responsibility for the performance or implementation of which is an obligation of the corporation and used in or for the construction, purchase, acquisition, or operation, of the property and works of the corporation, including its working capital, less however the amount of any interest that it may collect on moneys owing to it;

(c) the sum that, in the opinion of the board, should be provided in each year for the reserves or funds to be established and maintained pursuant to subsection 40(1).

Fixing of price by corporation

39(2) Subject to Part 4 of The Crown Corporations Governance and Accountability Act *and to subsection (2.1), the corporation may fix the prices to be charged for power supplied by the corporation.*

The CCGA and *The Manitoba Hydro Act* are consistent in limiting the PUB's rate approval jurisdiction as it relates to Manitoba Hydro to the price charged by Manitoba Hydro for power *supplied by* Manitoba Hydro. The operative words in section 39 of *The Manitoba Hydro Act* of "prices payable for power supplied by the corporation" and "prices to be charged for power supplied by the corporation" are clear and unambiguous. The legislation refers to a sale by Manitoba Hydro, not a purchase by Manitoba Hydro.

The jurisdiction afforded to the PUB pursuant to the legislative regime does not provide the PUB with authority to review and approve the price paid by Manitoba Hydro for any of its power purchases. Thus, Manitoba Hydro submits that the PUB does not have jurisdiction to review or approve the excess energy price charged by Manitoba Hydro for distributed generation electricity (which include solar and wind generation) it purchases. The excess energy price has been explained by Manitoba Hydro as being a historic market price. NUG customers are able to see the historic prices and current excess energy price posted on Manitoba Hydro's website. It is transparent, reasonable and informs customer's decisions.

It is worth mentioning that section 38 of *The Manitoba Hydro Act* demonstrates that the legislature turned its mind to Manitoba Hydro acquiring power from power producers in Manitoba. The legislature did not grant the PUB jurisdiction to review such purchases generally, but instead only in the limited circumstance where the power was expropriated by means of Order-in-Council. Where an arrangement is made between Manitoba Hydro and a customer for the voluntary supply of power to Manitoba Hydro, as with all of its NUG customers, the PUB's power to review the price established in the transaction under section 38(2) does not arise.

18. BILL AFFORDABILITY

18.1. Holistic Manitoba Hydro Programs

Manitoba Hydro knows some of its customers are struggling with their ability to pay their bills. As such, Manitoba Hydro offers a holistic approach through bundling of programs, as well as referrals, depending on the needs of each customer.[424]

Manitoba Hydro provides referrals to its customers for programs from Efficiency Manitoba such as the Energy Efficiency Assistance Program for low-income families, general program rebates, and the Indigenous Community Energy Efficiency Program among others. These programs are designed to help customers use energy wisely and lower their energy bill. To enable these programs offered by Efficiency Manitoba, Manitoba Hydro provides financing for customers through the Home Energy Efficiency Program and the Energy Finance Plan.

For customers that hold arrears, Manitoba Hydro offers Flexible Payment Arrangements and the Customer Arrears Assistance Plan ("CAAP"). Manitoba Hydro provides between 100,000 to 150,000 Flexible Payment Arrangements to help customers structure their bill payments. CAAP was first piloted in 2018 and was borne out of the bill affordability working group with participation from various stakeholders and Interveners. CAAP is an interest-free repayment plan, with amortization up to 3 years and in some exceptional cases up to 5 years. Approximately 1,500 to 2,000 customers participate in this program each year with interest free loans.[425]

Manitoba Hydro developed the Neighbours Helping Neighbours program which provides a one-time grant of up to $400 for customers in arrears at risk of disconnection and are

[424] Exhibit MH-33, Asset Management and Capital Direct Evidence Presentation, May 23, 2023, slide 29; Transcript May 23, 2023 page 1191.
[425] Transcript May 23, 2023, page 1192.

not currently receiving social assistance. Over $3 million has been dispensed through partnership with the Salvation Army since the program's inception in 2004. Through its customer surveys and an increase in customer arrears since the pandemic, Manitoba Hydro knows customers are having a harder time pay their bills now and as a result, it is actively working to expand the Neighbours Helping Neighbours Program.[426]

In addition, Manitoba Hydro's Customer Engagement Centre staff speak with customers daily and identify opportunities to further assist customers by waiving security deposits or removing late payment charges, for example. Other times, more support is needed than what Manitoba Hydro can offer. Where further social supports are needed, Manitoba Hydro staff provide customers with contact information for a number of agencies that can provide additional resources and support, like Harvest Manitoba, Rent Relief Fund, New Journey Housing and Crisis Lines, among many others.[427]

18.2. First Nation Customer Concerns, Reconciliation & Energy Poverty

MKO stated in its opening comments that its intervention will focus on the impact of rate increases on residential First Nations' customers and on reconciliation evidence.[428] Similarly, AMC stated in its opening statements that its member First Nations are extremely concerned with the rates of energy poverty faced by First Nations residential customers.[429] AMC stated that while it understands different rates for different customers or classes of customers must not differ based on affordability or other socioeconomic factors, this does not preclude bill unaffordability, particular in relation to First Nations customers.[430]

Manitoba Hydro accepts that it has a role to play in advancing reconciliation. As stated by Ms. Grewal, "[t]he legacy of the past remains a strong influence on Manitoba Hydro's relationship with Indigenous communities today, and we remain committed to establishing and maintaining strong, mutually beneficial relationships with Indigenous communities."[431]

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[426] Transcript May 23, 2023, page 1193.
[427] Transcript May 23, 2023, page 1194.
[428] Transcript May 15, 2023, page 151.
[429] Transcript May 15, 2023, page 343.
[430] Transcript May 15, 2023, page 346.
[431] Transcript May 15, 2023, page 163.

As a Crown corporation, Manitoba Hydro's approach is guided by *The Path to Reconciliation Act*[432] and it has been working to strengthen its relationships with Indigenous communities and to contribute to reconciliation efforts in its actions.[433] Manitoba Hydro seeks to continue its engagement with Indigenous nations and peoples and develop a deeper understanding of Indigenous issues and perspectives. Manitoba Hydro has taken action in advancing reconciliation, and it has over 800 agreements it has with First Nations and Indigenous parties.[434]

Manitoba Hydro recognizes that bill affordability and energy poverty issues are of increasing concern to First Nations customers and many others. The PUB has past and ongoing concern with utility bill affordability issues and Manitoba Hydro acknowledges the PUB's comment in Order 137/21 that it "expects Manitoba Hydro and Interveners to bring meaningful solutions to these concerns."[435]

Manitoba Hydro offers a number of different programs (described above) that provide different kinds of relief to anybody who needs support, including First Nations customers. It will waive deposits for low-income customers and Indigenous customers on reserve on a case-by-case basis.[436] A dedicated First Nations customer account team also provides support and resolves issues related to arrears, payment arrangements and pro-active disconnection notifications.[437] While a majority of these programs have been in existence for a number of years, they still provide meaningful solutions as evidenced by the continued use by Manitoba Hydro customers. Learning about customer needs, listening to customer feedback and evaluating programs is an ongoing process, and Manitoba Hydro's customer group is always looking to find meaningful ways to help its customers.[438]

Further, Manitoba Hydro always carefully balances the financial health of the utility with the impact on customers when determining the level of rate increases required. As Mr. Tess stated, "affordability has been specifically incorporated into the rate development

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[432] *The Path to Reconciliation Act*, C.C.S.M. c. R30.5.
[433] AMC/MH I-34a-e.
[434] Transcript May 15, 2023, pages 274-275; See also the response by Mr. Aurel Tess at Transcript May 30, 2023, pages 2243-2244.
[435] PUB Order No. 137/21, page 14.
[436] Transcript May 23, 2023, page 58.
[437] Transcript May 23, 2023, page 60.
[438] Transcript June 6, 2023, page 3514.

process through consideration of the magnitude of bill impacts of each of the proposed rate design changes."[439]

The issues underlying bill affordability and energy poverty are complex and engage considerations of social policy, and such issues cannot be solved by Manitoba Hydro alone. Manitoba Hydro has made extensive legal submissions on the jurisdiction of the PUB in past proceedings and before the Manitoba courts. Manitoba Hydro reiterates the findings from the Manitoba Court of Appeal that "initiatives to address broad social issues such as poverty should be left to the government"[440] and "the ability to consider factors such as social policy and bill affordability in approving and fixing rates for service does not equate to the authority to direct the creation of customer classifications implementing broader social policy aimed at poverty reduction."[441]

Given Manitoba Hydro's mandate, current legislation, and the passing of Bill 36, Manitoba Hydro is currently prohibited from creating bill affordability programs that target one group of residential customers. As summarized by Ms. Grewal, "energy poverty are social policy and Bill 36 precludes us from doing anything that is different for one class or set of customers versus another set of customers that would be in the same class."[442]

19. RATES & COST OF SERVICE

The Rates and Cost of Service panel discussed the phases of the rate setting process as described by the NARUC Electric Utility Cost Allocation Manual, which are followed by Manitoba Hydro, in its direct evidence presentation on June 6, 2023. In the first step, the overall level of the revenue requirement is determined. In the next step, the Cost of Service Study is used to apportion the total revenue requirement to each customer class. The Cost of Service Study evaluates the allocated revenue requirement against the revenues expected to be generated by rates, and determines the Revenue to Cost Coverage ("RCC") ratio for each customer class. And finally, the Rate Design Phase is the last step in the rate development process and is the determination of a pricing structure that will recover the utility's revenue requirement. This includes both the rate

[439] Transcript June 6, 2023, page 3394.
[440] Manitoba (Hydro-Electric Board) v. Manitoba (Public Utilities Board) et al, 2020 MBCA 60, paragraph 55.
[441] Manitoba (Hydro-Electric Board) v. Manitoba (Public Utilities Board) et al, 2020 MBCA 60, paragraph 85.
[442] Transcript May 15, 2023, page 264; See also the response by Mr. Aurel Tess at Transcript May 30, 2023, pages 2233-2234.

differentiation proposals as well as how the proposed rate increases are applied to the individual rate components. The following sections summarize the key issues in the second and third steps of the rate setting process.

19.1. PCOSS24 is Appropriate for Rate Design

The methodology used in the current Prospective Cost of Service Study ("PCOSS24") fully reflects the directives from PUB Orders 164/16 and 59/18. Methodology changes related to Directives 24, 25, 26 (service drops) and 27 were previously incorporated in PCOSS21, which was filed as MFR 20 of the 2021/22 Interim Rate Application and the last outstanding directive related to cost of service methodology (Directive 26 of 59/18 related to the sub-functionalization and allocation of common costs) has been updated for PCOSS24.

Mr. Bowman has endorsed the use of PCOSS24 other than proposed methodology changes addressed in the following sections and which he appeared to concede do not require immediate resolution during his oral testimony:

> *"The data inputs to PCOSS24 appear to be properly prepared and reasonable reflections of the GRA financial forecast scenario. For this reason, outside of methodological issues noted in this submission re: revenue requirement preparation or COS methods, the results of PCOSS24 can and should be applied to rate setting at this time."* [443]

Ms. Derksen suggests that the results of PCOSS24 are skewed by the addition of significant generation and transmission investment, high level of export revenue, and reductions in government fees, and as a result cannot be relied upon to differentiate rates.

Manitoba Hydro has addressed and disproved these assertions in its Rebuttal Evidence[444] at pages 103 to 108 and 122 to 125. As noted in Manitoba Hydro's Rebuttal Evidence, the major capital projects are now fully in-service and provide certainty on the costs of the significant investment in generation and transmission and anticipated depreciation and

[443] MIPUG-6, InterGroup Intervener Evidence – April 3, 2023, page 47, PDF page 50.
[444] MH-24.

finance expense for the upcoming years. In the case of net export revenue,[445] Manitoba Hydro concurs that the very high levels forecasted in 2023/24 do contribute to more variability than has historically been experienced; however, this factor was explicitly recognized in Manitoba Hydro's rate proposals as discussed in Section 8.4.2 of Tab 8. In the case of the reduction in payments to government, which are expected to continue in perpetuity, and beyond the initial impact in the test year which reduced costs for all, there is no instability created as a result of this reduction. Manitoba Hydro has demonstrated that the Residential class is expected to pay 1.1% less in 2023/24 and 2.6% less cumulatively in 2024/25 than they would have in absence of the fee reductions[446] and that Ms. Derksen's claim that the reduction in fees has somehow resulted in an increase in cost for the Residential class[447] simply has no merit.

As a result, Manitoba Hydro submits that PCOSS24 is a suitable tool for the Board to consider while adjudicating on just and reasonable rates in both test years. As noted in by Ms. Van Hussen:

> *"[…] the methodology used in PCOSS24 is fully complaint (sic) with PUB direction in Orders 164/16 and 59/18. Between PCOSS02 and PCOSS14, a variety of cost allocation methodologies were used as the studies were modified to reflect divergent views on cost causation. This is -- this had the result of limiting the amount of rate differentiation implemented during this period. Since Order 164/16 and 59/18, the methodology is no longer in a state of flux and is an appropriate basis to use for rate differentiation."*[448]

19.2. Recognition of the Capacity Component of Wind is not Required at this Time

Mr. Bowman states that "the facts today are clearly no longer consistent with the Board's findings that wind is an energy-only resource that does not contribute to winter peak capacity."[449] Mr. Bowman then recommends that wind should be classified as 20%

[445] For the purposes of cost allocation Net Export Revenue (NER) is defined as Export Revenue less variable hydraulic O&M, water rentals related to export volumes only, and amortization of the Affordable Energy Fund.
[446] MH-24, MH Rebuttal, page 125.
[447] Transcript June 8, 2023, page 3782.
[448] Transcript June 6, 2023, pages 3401-3402.
[449] MIPUG-6, InterGroup Intervener Evidence – April 3, 2023, page 49.

Demand and 80% Energy rather than the 100% Energy classification directed in Order 164/16 and reaffirmed in Order 59/18. In Order 59/18, the PUB recognized wind's limited contribution to winter peak but found that refinements to address the now-recognized capacity benefit of wind would add complexity to the COS with minimal benefit.[450]

The current Supply and Demand table[451] includes wind capacity of 52MW in 2022/23 which declines to 31MW by 2027/28. The wind capacity in question is equivalent to or lower than the amount that was considered and dismissed by the Board in Order 59/18. Therefore, Manitoba Hydro submits that the benefit associated with Mr. Bowman's proposed revisions to the classification of wind remains minimal.

The revenue to cost coverage ratio impact of adopting Mr. Bowman's proposed 80% Energy and 20% Demand classification for wind into PCOSS24 was provided in response to MIPUG/MH II-32b. The change would increase the RCC for GSL 30-100kV and GSL >100kV by 0.2% and 0.3% respectively. The impact for the remaining classes ranges from -0.1% to 0.1%.

During cross-examination, Mr. Bowman agreed that a methodology change was not required as an outcome of the current proceeding and could be deferred until after the review of the Integrated Resource Plan:

> *"MR. SVEN HOMBACH: Let's move on to those areas of cost of service where you are recommending changes. And, Mr. Bowman, let's start with the issue of wind capacity.*
>
> *Now, your suggestion is that there is actually a capacity component of wind energy at this point in time, right?*
>
> *MR. PATRICK BOWMAN: Well, it's not my suggestion. It's – it's part of – it's integral to Hydro's planning. It's in the numbers, and – and this Board has actually, if I recall correctly, acknowledged that in – in findings and Orders.*

[450] PUB Order 59/18, page 187.
[451] MH-1, Application Tab 7, page 13.

MR. SVEN HOMBACH: Would it be more appropriate, if the Board were to incline to make such a change, to do this after the IRP has been reviewed?

MR. PATRICK BOWMAN: I could accept that." [452]

Mr. Bowman provided a summary of Manitoba Hydro's use of the System Load Factor approach to classifying generation and how wind fits within this framework, but did not appear to make an explicit change from his initial recommendation to use a 20% Demand classification:

"MR. PATRICK BOWMAN: Generation classification, in this jurisdiction, looks at generation as a whole, where generation includes Bipole III – or in Bipole I and II. That is a generating unit complement hydrothermal (sic), all the different pieces, and it takes all of that together and says, the best way we consider how that entire group works together is to consider it the system load factor.

It takes the full sum of all of the entire system and it doesn't try to say, well, this hydro unit is for peaking and this one's for energy or these thermal units or this fuel. No. We take the entire group and we treat it as a system load factor, 'cause it works together as an integrated whole.

The exception off on the side is this wind. We say, oh, well, that's not really part of this grand whole. It's this extra little goody on the side that produces only energy, so, we'll give it a hundred percent energy, and, as a result, the end result is that it's actually a little bit weighted towards energy more than the system load factor, as if wind is not an integral part of the system. My submission is wind is an integral part of the submission – system. It's going to be a growing part of the system. Nothing's new in the way we – the assets that we have. We always had wind. It always gave a small capacity benefit. There is no real debate that it gives a capacity benefit."[453]

Manitoba Hydro notes that other exceptions of water rentals and variable hydraulic

[452] Transcript June 9, 2023, page 4128.
[453] Transcript June 9, 2023, pages 3997-3998.

O&M, which are also classified as 100% Energy, were not identified by Mr. Bowman.

Ms. Derksen's position on the classification of wind is unclear. Slide 36 of her June 8, 2023 direct evidence presentation[454] outlines Mr. Bowman's recommendation, as well as a summary of the Board's findings from Order 59/18. The slide deck does not provide her position or recommended treatment. Ms. Derksen did not address this slide or discuss wind during her oral testimony.

Mr. Madsen did not provide any comments related to Manitoba Hydro's Cost of Service Study in his pre-filed evidence and has not yet provided any recommendations related to the methodology used in the study thus far.

Manitoba Hydro agrees with Mr. Bowman's characterization that the System Load Factor approach relies on a simplified view of generation resources in order to classify Generation as a whole. While not specifically recommended by Mr. Bowman, Manitoba Hydro submits that including Wind as part of overall generation pool where it would be classified 60.7% Energy and 39.3% Demand is more consistent with the System Load Factor approach than either the current classification as 100% Energy or Mr. Bowman's proposal to recognize a 20% Demand portion.

Manitoba Hydro submits that an increased reliance on wind generation in the coming years may require a re-evaluation of the treatment of wind once the additional wind is included in the COS revenue requirement, however it does not necessitate a modification to the COS methodology at this time.

19.3. Nothing has Changed Since DSM was Determined to be a System Resource

Bowman states that "DSM costs should be functionalized to generation and transmission and distribution in proportion to the marginal values used to justify the programming, or approximately 75%, 10%, 15% respectively."[455]

During cross-examination, Mr. Bowman acknowledged that Efficiency Manitoba did not have a specific mandate to reduce transmission or distribution peak demand, and that

[454] CC-27, Kelly Derksen Direct Evidence Presentation, June 7, 2023, slide 36.
[455] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 53.

while changes may be required over the longer term to recognize the growing importance of capacity an immediate change to the PCOSS methodology is not required:

> *"MR. SVEN HOMBACH: And, with Efficiency Manitoba not having a capacity or demand reduction mandate, there is no focus by that util -- by that entity on reducing peak demand, specifically, is there?*
> *MR. PATRICK BOWMAN: I -- I don't know that Efficiency Manitoba is pursuing any programs, specifically, to reduce transmission or -- or distribution peak demand. I -- I -- I certainly hope they're attentive to it because we -- we need it and we're going to need it more and more, as we go into the future.*
>
> *MR. SVEN HOMBACH: But if, currently, those savings are ancillary to the DSM programming that's focussed on energy, is it cost/causal to functionalize them as transmission and distribution costs?*
>
> *MR. PATRICK BOWMAN: From an economic perspective, if nor -- normalized energy is 5 1/2 cents and shaped energy, including peak savings, are 7 cents and those are being taken into account, in the decisions being made at Efficiency Manitoba, then the difference between 5 1/2 and 7 is causing investment.*
>
> *That -- yes, it's cost/causal in that - - in th*at perspective. But, again, I would even -- ***I would accept, similar to wind, that these are directional improvements that should be thought about over time.***
>
> ***I -- I -- I would hope Efficiency Man - - Manitoba comes back, the next time, with a focus on -- on the benefits they can bring to transmission and distribution, and I think that that will probably even evolve more over time. These are going to be significant, acute issues going into the future."*** [456] [**emphasis added**]

Ms. Derksen's direct evidence presentation[457] referenced the treatment of DSM directed

[456] Transcript June 9, 2023, pages 4131-4132.
[457] CC-27, Kelly Derksen Direct Evidence Presentation, June 7, 2023, slide 35.

in Order 164/16 and Centra Order 109/22, and disputed how Mr. Bowman represented the following excerpt from the PUB Report on Efficiency Manitoba which was included in his evidence:

> *"With respect to the electric DSM portfolio, the marginal value is based on the value to Manitoba Hydro of the electricity conserved by the DSM programs. Manitoba Hydro receives value from conserved electricity by having more electricity available to export, potentially under long-term firm contracts, as well as due to the deferral of* ***future transmission and distribution investments*** *as a result of reduced load growth and consequent reduced capacity requirements."*[458] [**emphasis added**]

Mr. Bowman characterized the excerpt as a finding of the Board, while Ms. Derksen claims "the Board did not provide any findings on the deferral of future transmission and distribution requirements, it was simply re-iterating a perspective of Mr. Harper from the 2016 COSR as part of the background (EM Report, pg.65 – are not PUB findings)."[459] A review of the PUB Report on Efficiency Manitoba did not immediately reveal the basis of the claim that this was not a PUB finding.

Ms. Derksen's position on DSM or any recommended treatment of DSM is unclear. Ms. Derksen did not address this topic during her oral testimony.

Mr. Madsen did not provide any comments related to Manitoba Hydro's Cost of Service Study in his pre-filed evidence and has not yet provided any recommendations related to the methodology used in the study thus far.

On pages 127-129 of its Rebuttal Evidence, Manitoba Hydro has established that:

- there has been no change to the marginal value assumptions underlying the evaluation of DSM based on whether the programming is being undertaken by Manitoba Hydro or Efficiency Manitoba;
- despite the direction given in 164/16 to treat DSM as a generation resource, the PUB also acknowledged and considered the potential for deferring transmission and

[458] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 50, PDF page 53.
[459] CC-27, Kelly Derksen Direct Evidence Presentation, June 7, 2023, slide 35.

distribution assets; and

- while it is expected that DSM will result in some deferral of transmission and distribution, the method Mr. Bowman recommends of apportioning costs to the individual functions is neither indicative nor reflective of the value of savings realized by efficiency programming being undertaken.

The only new fact on the record in this proceeding was provided by Manitoba Hydro in response to Undertaking 55[460] where it was established that Distribution planning does not consider forecast DSM savings when planning projects.

Manitoba Hydro submits that the facts have not changed since the PUB provided direction in Order 164/16 to functionalize DSM as Generation, and despite suggestions, no evidence has been presented in this hearing to support including any specific portion of DSM to the Transmission or Distribution functions.

19.4. It is Pre-mature to Re-evaluate use of Top 50 Hours

Mr. Bowman proposed that the annual hours used to develop the Coincident Peak Demand allocator be reduced from the current practice of using the top 50 winter hours to incorporating as few as one hour and no more than 6 hours. He recommended continuing the practice of using the average of eight years of load data:

> *"Recommendation 15: The PCOSS Coincident Peak allocator should be calculated on the eight-year average of the highest single hour, or at most a very limited number of hours each year (e.g, 4-6 hours per year)."* [461]

During cross-examination, Mr. Bowman clarified that he was not recommending the use of a single hour to determine Coincident Peak Demand and that including up to 10 hours averaged over 8 years may be a reasonable approach to normalize the actual demand data for a class such as Area and Roadway Lighting.[462]

Ms. Derksen recommends the Board rejects a "very narrow" definition of coincident peak

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[460] MH- 54,Undertaking #55.
[461] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 55, PDF page 58.
[462] Transcript June 9, 2023, pages 4133-4136.

demand since it:

- "Fails to consider the integrated nature of and coordinated planning of MH's generation and transmission system;
- Incohesive with the broader considerations of cost allocation underpinning MH's current COS methodology;
- Would unwind much of Order 164/16." [463]

Ms. Derksen did not address this slide or discuss the topic during her oral testimony.

Mr. Madsen did not provide any comments related to Manitoba Hydro's Cost of Service Study in his pre-filed evidence and has not yet provided any recommendations related to the methodology used in the study thus far.

Ms. Van Hussen explained why Manitoba Hydro made the switch in PCOSS99 to calculate the coincident peak demand allocator based on the average demand over the top 50 winter hours, rather than based on the highest single hourly demand which was the approach used in earlier studies:

> *"MS. MARNIE VAN HUSSEN: It's been a long standing practice to use fifty (50) hours. It first came about the late '90s, perhaps even sooner. I can find that out. But it was really to deal with the fact that area and roadway lighting may be on in some hours and may be off in some hours.*
>
> *So, if you use a single hour you may have a class that either is entirely on and contributing to that peak or they may be entirely off and contributing to that peak.*
>
> *So, it would have a -- a very big impact on whether an entire class received any demand costs. So, fifty (50) hours was to sort of attenuate and average out whether certain classes would be on or off.*

[463] CC-27, Kelly Derksen Direct Evidence Presentation, June 7, 2023, slide 34.

And area and roadway lighting is sort of the extreme example of that. They're either on or off, but you also have individual classes where if you -- if you chose a single peak hour, that single peak hour can move.

It's not always at the same time in Manitoba Hydro's system, but it may make the difference on whether a commercial customer or industrial customer was operating in those hours.

So it's also just to get a better sense of the -- which classes are contributing to that peak that -- that does sort of move around throughout the day." [464]

Manitoba Hydro uses coincident peak demand to allocate Generation, Transmission and Subtransmission costs. The winter peak hour in Manitoba can occur in the morning or early in the evening. Selection of only one of those hours as a winter peak would not necessarily be representative of all hours in which the peak could occur and may bias the allocation of peak-related costs toward a particular class or classes of service. For example, use of a peak occurring in the mid-morning could overstate peak responsibility of the General Service Small and Medium classes whereas use of a peak occurring in the early evening could overstate peak responsibility of the Residential and Area and Roadway Lighting classes.

The definition of coincident peak (CP) demand was re-evaluated for PCOSS99 to address this potential bias and was primarily focussed on moderating the significant year-over-year variation in demand costs and the RCC for the Area & Roadway Lighting class ("A&RL"). Using the average over 50 hours captures a more representative array of peak conditions and eliminates the randomness of streetlights either being fully on or entirely off during the coincident peak depending on the specific peak hour in the load data used in the PCOSS.

Class non-coincident peak (NCP) demand is used to allocate Distribution costs in the PCOSS. Since the NCP demand is measured at the time of the peak for each class there are no similar concerns with determining the appropriate time to measure the demand, and the calculation continues to be based on a single hour.

[464] Transcript June 6, 2023, pages 3455-3456.

However, CP demand and class NCP demand may also be affected by atypical weather conditions in any one year. This potential variability was not addressed until PCOSS10 when Manitoba Hydro started using averaged results from multiple Load Research studies to minimize year-over-year variation and provide a measure of weather-normalization compared to using a single year. The use of 50 hours had already moderated this variability in the CP demand calculation, but, for consistency, the eight-year average was adopted for both CP and NCP demand.

As discussed in Appendix 8.1, Manitoba Hydro is in the process of updating its load forecasting and load research methodologies, which will require changes to the process of developing estimates of class demand to use in the PCOSS:

> *"PCOSS24 utilizes the average of eight years of load and coincident factors from the 2007/08 to 2014/15 Load Research studies, consistent with the studies used in PCOSS21.* ***Manitoba Hydro is currently developing customer hourly load profiles to improve its load forecasting methodologies****. Manitoba Hydro plans on using these hourly load profiles to develop estimates of class coincident peak at generation and class non-coincident peaks for use in future Cost of Service Studies. Using hourly load profiles will allow for more direct determination of class peaks without the use of load factors,* ***allow greater flexibility to consider alternate definitions of peak demand****, and provide the opportunity to explore hourly allocation methodologies."* [465] [**emphasis added**]

Manitoba Hydro does not intend to continue the previous process of estimating peak demand using historic load factors based on pre-defined parameters (e.g., top 50 hours). Instead, demand will be determined using 8,760 class hourly load shapes. Given the same data set, either the load shape or load factor approach will yield the same results, but the load shape approach allows more flexibility.

The hourly load profiles are forecast load shapes which are expected to be based on three to five years of actual consumption for each class, subject to data availability. The current practice of using the average of eight years of load research data in the PCOSS will no

[465] MH-1, Application Tab 8, Appendix 8.1, pages 52-53.

longer be feasible and will need to be re-evaluated in addition to the use of the Top 50 hours.

Manitoba Hydro submits that it is premature to re-evaluate the use of the top 50 hours to calculate CP demand at this time based on the limited evidence available in this proceeding. It would be more appropriate and efficient to review the definition of CP demand as part of the load research update, and subsequently provide an analysis of CP Demand in a future PCOSS.

19.5. Relevant Considerations once Data is Available to Re-evaluate Top 50 Hours

Ms. Derksen questions whether Mr. Bowman's recommendation on the top 50 hours is limited to revising only the CP Demand used for the Transmission function or if the modification is also intended to be used for Generation.[466] It is not specifically stated in Mr. Bowman's written evidence, but in the absence of any indication to the contrary, Manitoba Hydro has assumed that Mr. Bowman is recommending that a single version of CP Demand continue to be used throughout the PCOSS.

Manitoba Hydro recommends retaining the current practice of using a single and consistent definition of CP Demand to allocate the Demand-related portions of Generation and Transmission, as well as Subtransmission. Many stakeholders struggle with the concept of demand, which can have a number of definitions, compared to the relatively straightforward concept of annual energy consumption. Manitoba Hydro submits that using multiple versions of CP Demand, in addition to the existing class NCP Demand, will reduce stakeholders' ability to understand the COS without improving cost causation and should be avoided.

During cross-examination, Mr. Bowman observed that increasing the number of hours included in CP demand effectively turns the demand allocator into an energy allocator:

> *"MR. PATRICK BOWMAN: It would be attenuated, if you take an eight-year average. Yeah, but -- but, again, I'm, like I said, -- I'm not -- I'm not saying ruthlessly one (1) hour. If you took some -- some small number of hours*

[466] CC-27, Kelly Derksen Direct Evidence Presentation, June 7, 2023, slide 33.

each year and, then, looked at those over eight (8) years, we still have a fairly -- fairly wide number of peaks we're looking at and it's -- it's interesting.

I was handed the -- the 1992 NARUC Manual, assuming that people would use it for cross. I -- I guess they didn't, but it -- it was interesting how it mentions the greater the number of hours used, the more the allocator will reflect energy requirements, which says it more eloquently than I --than I could.

But, as we expand that peak, what we're, effectively, doing is taking costs and we say that cost is driven by -- by -- by peak -- by demand, and we're, effectively, turning it into an energy allocator by expanding out the number of hours." [467]

Manitoba Hydro agrees with both Mr. Bowman and the NARUC Manual that as you move from load in a single hour to load over a larger number of hours, the allocator begins to transform from a demand allocator into an energy allocator. There is no clear demarcation where it has fully transformed into an undeniable energy allocator, but Manitoba Hydro submits that the transition point is clearly not 50 hours that represent 0.6% of annual hours. Secondly, averaging demand over multiple years does not have the same effect as increasing the number of hours from a given year. The top 50 hour CP demand captures 0.6% of annual hours whether it is based on one year (50/8,760 hours) or the averaged results over eight years (400/70,080 hours).

Mr. Bowman also cautioned that it was not appropriate to expand the number of hours used for Coincident Peak Demand allocator if the only purpose was to assign demand costs to a class that does not use the system during peak periods:

"I would say, if I was the -- the -- dealing with the street light class, if -- if we use something like eight (8) or ten (10) hours, as an example for a peak, six (6) hours, something in -- in that nature, to measure the peak in a given year, and we looked over eight (8) years, if the street lights - - if those peaks

[467] Transcript June 9, 2023, pages 4135-4136.

are happening during the day and the street lights aren't on, then I don't know why they're being allocated at peak costs.

The data will tell us whether that allocation is needed. We don't want to expand the data set in order to pick up a bunch of hours that are not peak, just so we can find a way to stick some costs to street lights.

If -- if they're not on during the peak hours, if the peaks are happening at 11:00 a.m. or -- or -- or at noon, on cold days, and the street lights are off, then -- then we don't need to allocate peak costs to street lights. They're not contributing to the investment in -- in peak and, if that's averaged over eight (8) years, maybe four (4) will be on and four (4) will be off, in which case, they would get the allocation. If none of them are on over eight (8) years, then, they don't need an allocation." [468]

In the previous section, Manitoba Hydro explained that the use of 50 hours was intended to avoid year over year variation in cost and RCC for A&RL due to changes in the peak hour. This was not an attempt to target any specific level of responsibility of demand costs for the lighting class.

Ms. Derksen provides an extensive list of additional factors that she asserts need to be considered when evaluating the number of hours to include in the definition of CP demand and recommends that if a narrower view of CP Demand is adopted then the classification of Transmission should be based on System Load Factor ("SLF").[469]

Manitoba Hydro's decision to use 50 hours in PCOSS99 was based on professional judgement, was an assessment of the sample size required to reduce variation and was not based on the many factors listed by Ms. Derksen. Similarly, any future evaluation of whether the variation can be addressed by using less than 50 hours should be a comparatively simple exercise that does not involve the overly complicated and unrelated factors cited by Ms. Derksen.

Since the use of CP demand based on the top 50 hours was not intended to capture any

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[468] Transcript June 9, 2023, pages 4134-4135.
[469] CC-27, Kelly Derksen Direct Evidence Presentation, June 7, 2023, slide 33.

energy considerations, there is also no basis to Ms. Derksen's suggestion that reducing the hours in the demand allocator would require an offsetting increase in the energy component by switching to the use of SLF to classify Transmission.

19.6. Clarification of Normalization of Net Export Revenue in PCOSS Scenarios

PCOSS24 uses forecast export revenue for 2023/24 which incorporates projected above average starting reservoir levels and assumes average revenues and costs based on simulations using the 40-year flow record. The water conditions used in the study and the potential for further normalization were the subject of the cross-examination of Mr. Bowman, who invited parties to confirm his understanding of the information requests he relied upon given the unexpected level of attention that was given to the topic in the hearing:

> *"DR. BYRON WILLIAMS: And in your evidence, sir -- I can take you there if you like -- but conceptually, you would agree that the PCOSS scenarios could be normalized for water flows. Agreed? So -- and sir, you understand?*
>
> *MR. PATRICK BOWMAN: I do.* ***I just want to caution, again, the flows versus starting reservoirs issue.***
>
> *I* ***think the PCOSS scenarios are normalized for water flows. They're not necessarily normalized for starting reservoir conditions.***
>
> *DR. BYRON WILLIAMS: Yeah. Exactly. And sir, assuming one wanted to normalize for system inflows and for water levels to -- to try and normalize that inherent volatility, I wonder, as an independent expert, if you could offer some preliminary thoughts on considerations you might recommend in terms of a principled approach to normalizing system water flows, inflows, as well as reservoir levels for the purpose of PCOSS analysis.*
>
> *MR. PATRICK BOWMAN: Well, as I noted, flows are already normalized. As far as, you know, the -- the range of expected projections. Inflows.*

The water levels could be normalized if that was an objective that one set out to do. And I think that was done. I was just trying to find the reference.

It is -- it was in my presentation though. ***Double-checking here. It's PUB Response Round 1 141A and also Coalition Response Round 1 155A, which takes the reservoir levels at the start and -- and moves them to an average level.***

The result of those RCCs are shown in - - Ms. Schubert, if you have the presentation -- we -- I used it as a cross-check, as a matter of fact." [470] [**emphasis added**]

Mr. Bowman's portrayal of the starting reservoir and water flow assumptions used in PCOSS24 is correct, but the reference to the use of normalized water in the two alternate PCOSS scenarios requires clarification to ensure that the record is clear. Numerous PCOSS scenarios were prepared during this proceeding to provide indicative RCC impacts at various levels of export revenue (see Figure 39). However, none of the PCOSS scenarios provided used revised starting reservoir levels that had been explicitly normalized for use in the PCOSS or differed from the assumptions underlying the Financial Forecast Scenario.

In response to PUB/MH I-141a, Manitoba Hydro elected to provide a PCOSS scenario that used the forecast NER for 2024/25 (which reflects both average starting reservoir levels and average inflows) rather than normalize the starting reservoir levels for 2023/24.

The question posed in the information request was:

"Please provide indicative revenue to cost coverage ratios (RCC) if net export revenue (NER) for 2023/24 was based on average water flows, not the higher reservoir starting conditions of 2023/24. ***Alternatively, provide indicative RCCs using the forecast NER for 2024/25****."* [**emphasis added**]

Similarly, Coalition/MH I 155 b requested a scenario using 2024/25 NER:

[470] Transcript June 9, 2023, pages 4076-4077.

> "Please file the following PCOSS24 scenarios: 1) **assuming forecast export revenue as reflected in the 2024/25 fiscal year of the 20 Year Financial Forecast year of $964 million**; 2) assuming forecast export revenue of 70% of that reflected in PCOSS24 (that is, 70% of $1,154 million); 3) assuming forecast export revenue of 60% of that reflected in PCOSS24; and 4) assuming forecast export revenue of 50% of that reflected in PCOSS24." [**emphasis added**]

Fully normalizing export revenues to reflect average starting reservoir levels for the 2023/24 test year would require an alternate run of Manitoba Hydro's HERMES model to determine an updated calculation of net flow related revenues[471] which would include revised levels of export revenues, as well as changes to the amount of power purchases, water rentals and thermal fuel costs.

Manitoba Hydro submits that there is sufficient evidence on the record to allow the Board to consider class RCCs under a wide range of export revenue conditions, without the need to explicitly normalize the starting reservoir level.

This approach is consistent with the high-level assessment of potential variability from changes in export revenue that Manitoba Hydro considered when developing its rate differentiation proposals.[472]

Ms. Derksen's responses to Undertaking #64 provide estimated class RCCs based on the levels of Net Export Revenue forecast over the next five years, which are presented in a chart on page 1 of the undertaking. Manitoba Hydro notes that the source provided for the RCCs that reflect "2028/29 $694M NER", which is included with a list of references and assumptions on page 6, appears to be incorrect. Manitoba Hydro did not prepare any scenarios for this proceeding that utilized the 2028/29 level of export revenues.

The class RCCs in the chart do match those that were provided in response to Coalition/MH I-155 b3, which requested a scenario that assumed export revenues at 60% of the PCOSS24 level. However, the requested $693 million of export revenues (60% x

[471] Which are also referred to as "Net Export Revenue" under the alternate usage of the term as discussed on slide 12 of MH-30, MH Export, Drought Management and Hydrology Presentation – May 16, 2023.
[472] Coalition/MH I-155 e-f; Coalition/MH II-61 a-b.

$1,154 million) used in that scenario do not match the $740 million of export revenues that are included in the Financial Forecast Scenario for 2028/29. After the assignment of variable costs Coalition/MH I-155 b3 includes NER of $670 million, which similarly does not match the $694 million of NER shown in the legend for the chart in the undertaking.

Manitoba Hydro would like to ensure that the record is clear and that, although the RCC results provided appear directionally correct, they do not depict a scenario that actually incorporates 2028/29 export revenues.

Figure 39

Source	Export Assumption	Export Revenue ($million)	NER ($Million)
Appendix 8.1	2023/24 Forecast	1,154	1,116
PUB/MH I 141a	2024/25 Forecast	964	933
Coalition/MH II-61a	Based on range of export revenue forecast for upcoming years	1,000	962
		900	862
		800	762
Coalition/MH I-155b	70% of 2023/24 forecast	808	781
	60% of 2023/24 forecast	693	670
	50% of 2023/24 forecast	577	558
Coalition/MH I-137b	40-Year Flow Record – 25th Percentile	1,002	969
	40-Year Flow Record – Average	1,153	1,115
	40-Year Flow Record – 75th Percentile	1,278	1,236
	110-Year Long Term Flow Record – 25th Percentile	1,018	985
	110-Year Long Term	1,137	1,100

	Flow Record – Average		
	110-Year Long Term Flow Record – 75th Percentile	1,258	1,217

19.6.1. Rate Differentiation

Mr. Bowman depicts Manitoba Hydro's rate differential proposals as directionally consistent with the results of PCOSS24 but proposes higher level of rate-differentiation to move classes into the ZOR by no later than 2027/28.[473]

Mr. Madsen is "supportive of Manitoba Hydro's Cost of Service proposals related to GSS/GSM rate classes."[474] Manitoba Hydro understands this to mean the rate differentials being proposed on the basis of PCOSS24.

In contrast, Ms. Derksen proposes no rate differentiation except for a below average increase for GSSND[475] As the basis for her position, Ms. Derksen suggests that Manitoba Hydro's rate proposals are deficient as they are:

> *"(i) not considering the overall bigger picture of a large vertically integrated electric utility with billions of dollars of common costs to be allocated; (ii) an anomalous circumstance with record levels of NER and the largely self-correcting situation that RCCs will move into or close to the ZOR within a short period of time; and (iii) failure to consider rate design principles of fairness, equity, efficiency and public acceptability."*[476]

Manitoba Hydro's responses to each of these supposed deficiencies are provided below:

- The cost of service methodology underwent a thorough review in 2016. The level of the investment in Manitoba Hydro's generation and transmission assets that would be incorporated into the future PCOSS studies was understood at that point

[473] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 59, PDF page 62.
[474] Transcript June 2, 2023, page 2911.
[475] CC-10, Consumers Coalition Intervener Evidence, Kelly Derksen, April 3, 2023, page 60.
[476] CC-10, Consumers Coalition Intervener Evidence, Kelly Derksen, April 3, 2023, page 59.

in time. As such, it does not follow to suggest that the methodology and Manitoba Hydro's rate differentials that are underpinned by the results of a study incorporating that methodology do not consider the magnitude of the common costs or the fact that Manitoba Hydro is vertically integrated. Furthermore, Manitoba Hydro's use of the concept of a zone of reasonableness ("ZOR") considers the judgement required in preparing a cost of service study and that it is not possible to directly assign costs that are provided by common assets which comprise almost the entirety of Manitoba Hydro's system.

- Similarly, it was anticipated that additional export revenue would accompany the in-service of Keeyask. Manitoba Hydro acknowledged the effect that NER was having on the results of PCOSS24 and explicitly reflected that in the rate differential proposals as stated at page 13 of Tab 8: *"it is clear that PCOSS24 results are being driven by record levels of export revenue. Accordingly, Manitoba Hydro is proposing a smaller rate differential, relative to GSSND and A&RL, of 0.5% below the average increase be applied to these classes. This approach takes into account the more highly variable impacts that NER can have on RCCs as well as the longer timeframe over which the PUB's original directive to move class RCCs considered."*

- The PUB directed in Order 164/16 that rate making objectives should not be considered in the determination of the cost of service methodology and if required, should be considered at the rate design stage. However, it should not follow, nor does Manitoba Hydro believe, that it was the PUB's intention in Order 164/16 that rate design should ignore all changes in cost responsibility produced within the PCOSS. Class-cost responsibility has changed as a result of changes in the numerous inputs into PCOSS24 and class cost responsibility will continue to change in the future as the industry, Manitoba Hydro, and customers continue to evolve. Failure to recognize legitimate changes in cost causation via rate differentials will undermine fairness and equity on an inter-class basis.

Manitoba Hydro respectfully disagrees with Ms. Derksen's assertions regarding its approach to rate differentials as discussed by Ms. Van Hussen:

> *"Mentioned at the previous slide, that rate design is not a mechanistic exercise, based solely on the results of the Cost of Service study. And,*

what that means is that Manitoba Hydro do not just supply [sic apply] the results of PCOSS24 without considering numerous other factors before determining our final rate proposals. In coming to our proposal, we looked at Manitoba Hydro's rate objectives, which Ms. Gregorashuk walked us through, Bonbright's traditional attributes of a sound rate structure, trends of RCCs over previous studies, RCC results relative to the zone of reasonableness, PUB direction in 59/18 to move classes into the zone of reasonableness, with any shortfall recovered from classes below or within the zone of reasonableness.

And, we considered whether there were any extenuating circumstances that required a departure from recent Board direction, or from previous practice. This included reflecting on revenue requirement inputs into cost of service, increasing importance of capacity, level of export revenue and marginal versus embedded costs. Overall, Manitoba Hydro has taken a balanced approach, that is cost based, is consistent with PUB direction in the past few rate cases, namely, 164/16, 59/18, 69/19 and 137/21, and appropriately incorporates policy considerations, when necessary." [477]

Ms. Derksen also asserts that Manitoba Hydro has failed to specifically consider marginal cost concepts, the fact that "net export revenues benefit some classes more greatly than others", and the Uniform Rate adjustment. Manitoba Hydro disagrees and has addressed the first two of these matters extensively on pages 103-116 of its Rebuttal Evidence. To summarize, the export price trend that first gave rise to Manitoba Hydro's previous concerns related to marginal cost and efficient prices signals in the early 2000s did not continue and short-run marginal costs and embedded costs started to converge. Short-run marginal costs (using most recent SEP prices as a proxy) and even long-run marginal costs (as noted in COALITION/MH II-57d) are now at levels that are not materially different compared to average revenues based on embedded costs and may continue to narrow with short-run marginal costs currently on a downward trajectory. These differences are certainly not substantive enough to warrant special consideration which, in Manitoba Hydro's view, would

[477] Transcript June 6, 2023, page 3411.

disregard the latest PUB direction related to the treatment of export revenues as expressed in Order 164/16:

"The Board finds that the revenue from export sales is linked to the assets that give rise to export sales revenues, which are Generation and Transmission assets only, not Distribution assets. To use Distribution costs to credit export revenue of any kind would be a disconnection to cost causation and thus inappropriate. The Board concludes that export revenues are not a "dividend" that can be assigned or based on considerations other than cost causation." [478]

In her direct testimony, Ms. Derksen noted her concerns with the lack of consideration of the uniform rates in Manitoba Hydro's rate design proposals:

MS. KELLY DERKSEN: "And in 164/16, the Board found that that was not an appropriate assignment of costs against export revenue, but it was a policy consideration that ought to be deal with as part of rate -- as part of rate design purposes, and Manitoba Hydro has -- has ignored that direction. They haven't factored that consideration at all in its rate differentiation proposals." [479]

On Slide 16 of her direct evidence, Ms. Derksen notes that the solution is "normalized URA for Rate Design purposes" but to date has not provided any specific recommendation on how this could actually be implemented in the rate design phase.

Based on Ms. Derksen's response to Undertaking #64 it appears that normalizing the Uniform Rate Adjustment ("URA") for rate design is a recommendation to perpetuate the previous approach that was used to implement the URA in the cost of service study. The dated PCOSS14 scenario that Ms. Derksen has put into evidence[480] and relied upon in her undertaking demonstrates the RCC impact that would occur from

[478] PUB Order No. 164/16, page 39.
[479] Transcript June 8, 2023, page 3777.
[480] Manitoba Hydro notes that the Coalition did not request any updated scenarios related to the implementation of the Uniform Rates Adjustment despite the 233 Coalition IRs (including subparts) that were directed to the Rate Analysis and Design department which resulted in 329 pages of responses.

eliminating the URA from the PCOSS14 study and not PCOSS24.

In PCOSS14 the uniform rates adjustment was incorporated into the cost of service in two steps:

1. Domestic class revenues were adjusted to offset the estimated revenue reduction that occurred due to the implementation of uniform rates
2. The adjustment to domestic revenues was assigned as a first charge against export revenues, with the resulting NER allocated in proportion to total costs. Both of these export practices have since been explicitly rejected in Order 164/16.

The assessment of normalizing URA that was provided in the undertaking should be considered to depict directional rather than absolute RCC impacts, due to the outdated revenue data and inconsistency of the methodology with current views on the use of export revenues.

An examination of the actual excerpt from Order 164/16 clarifies that the Board's direction was that uniform rates should only be considered during rate design but does not identify this as a problem that necessarily needs to be solved as one would infer from Ms. Derksen's evidence. The Board stated that: "Any impacts of the Board's COSS treatment of uniform rates on RCC ratios are a matter for consideration in rate design, not cost of service."[481]

Manitoba Hydro did consider the Uniform Rates Adjustment when developing its rate design proposal and concluded that:

- Addressing the impact that Uniform Rates had on the Residential, GSS, GSM and A&RL classes cannot be accomplished without explicitly adjusting the rate differentiation for other customer classes. The only remaining customers that could be conceivably called upon to fund the URA are the three GSL classes – two of which have RCCs that are well above the upper bound of the ZOR.
- At the current time, the modest level of rate differentiation included in Manitoba Hydro's rate design proposal only targets reaching the 95-105% bounds of the ZOR. The Residential RCC is at the lower bound of the ZOR and is arguably 5% below cost. This deficit is greater than the level of remedy that would be required

[481] Order 164/16, page 41.

to address the implementation of uniform rates and suggests that no adjustment is warranted for the Residential class in the current application.

- *The Manitoba Hydro Amendment and Public Utilities Board Amendment Act* will require that rates reflect properly allocated costs and appears to limit any practical means to implement URA considerations in future rate design once the new legislative framework is in effect. Manitoba Hydro submits that there may no longer be the latitude to make adjustments in rate design as were originally contemplated when the Board provided its direction in Order 164/16.
- Finally, Manitoba Hydro notes that uniform rates were implemented over twenty years ago and due to the passage of time it may no longer be reasonable to expect any specific remedy in COS or rate design to mitigate the impact it had on former Zone 1 customers.

19.6.2. Rate Differential for the Area & Roadway Lighting Class

Manitoba Hydro is proposing a below average increase for the Area & Roadway Lighting class in order to continue to migrate the RCC for this class into the ZOR. No intervener took a position with regards to the proposal for the Area & Roadway Lighting class except for Ms. Derksen who suggested the class should not receive a below average increase. It appears, however, that this conclusion may have resulted from a misinterpretation of Manitoba Hydro's evidence and also led to submission of erroneous evidence by Ms. Derksen. Examples include:

- Failure to understand how the 108% benchmark was used and that it has no impact on the overall level of rate differentiation sought for the A&RL class;[482]
- Erroneously claims that the A&RL RCC is higher in PCOSS24 due to the level of NER, Net Income and the reduction of provincial fees;[483] and
- Claims that Manitoba Hydro's proposal to directly assign a portion of the LED conversion costs is due to concerns about adequacy of G&T allocated to the class.[484]

[482] MH-24, MH Rebuttal Evidence, May 5, 2023, page 122.
[483] CC-10, Consumers Coalition Intervener evidence, Kelly Derksen, April 3, 2023, page 58; MH/Coalition I-6; MH-24, MH Rebuttal Evidence, May 5, 2023, page 121.
[484] CC-10, Consumers Coalition Intervener evidence, Kelly Derksen, April 3, 2023, page 49; MH-24, MH Rebuttal Evidence, May 5, 2023, page 118.

Manitoba Hydro has provided corrections to ensure the record is clear regarding the Area & Roadway Lighting class at pages 119-122 of its Rebuttal Evidence.

Manitoba Hydro agrees with Ms. Derksen[485] that the proposed assignment of LED conversion costs will only reduce the RCC of the A&RL class temporarily, but reaches different conclusions on how this should be reflected in rate differentiation. Manitoba Hydro submits that if the assignment of DSM costs is not accepted by the Board then the need for below average increases for A&RL is even more urgent since the class RCC would immediately increase by 11.8% to 120%.[486] Even if the methodology change is accepted, the impact of the direct assignment will steadily decrease as the DSM expenditures from the initial years of the LED conversion program are fully amortized resulting in a continuous trend of RCC increases for the class in the upcoming years. The modest level of rate differentiation proposed in this Application remains appropriate to mitigate these unavoidable RCC increases.

Manitoba Hydro requests approval of the one percent below average overall rate differentiation being proposed for the A&RL class.

No intervener has provided evidence on the Lighting Cost of Service Study ("LCOSS") or MH's proposal to apply a secondary level of revenue-neutral rate differentiation to A&RL rates based on the results of the LCOSS. Manitoba Hydro requests the incremental rate differentiation being proposed within the A&RL class also be approved.

19.7. Proposed Rate Design

19.7.1. General Service Small & Medium Classes

Given the diverse characteristics of the GSSND, GSSD, and GSM classes, continuing with rate harmonization will inhibit Manitoba Hydro's ability to sufficiently adjust rates for all three classes. As a result, Manitoba Hydro is proposing to discontinue rate

[485] PUB/Coalition I-17e "Principally speaking, this does not appear to be unreasonable. However, as discussed in part a) above, this does not address the material issue of concern, and a temporary fix as with forecasted reductions in NER over the next several years, the RCC of the ARL will once again increase to over 115%."
[486] MH-1, Application Tab 8, Appendix 8.1, Table 5.

harmonization for the GSM class and adjust rates for this class independently from those of the GSSND and GSSD classes, in order to move the GSSND class towards the ZOR. GSSND has been persistently above the upper bound of the ZOR since 2013. In conjunction with this change, Manitoba Hydro is proposing to continue the use of a declining block rate for General Service Small and Medium classes but consolidate the first two blocks of the GSM rate into a single threshold. Manitoba Hydro has also provided support for continued usage of the declining block rate structure in Section 8.7.1 of Tab 8, including an explanation of block thresholds as requested by the PUB in Directive 28 of Order 59/18.

It is notable that Mr. Madsen has endorsed the proposed rate design changes for the GSS/GSM classes:[487]

> *"Declining block rate structures are less common than they were historically. This is because they can encourage more consumption if designed inappropriately. However, in this case, I agree with the balance Manitoba Hydro has sought to strike as stated on pages 19 and 20 of Tab 08 of its application. I also note Manitoba Hydro's responses at COALITION/MH I-146 and PUB/MH I-144. Specifically, I note the following response to parts c) and d) of COALITION/MH I-146:*
>
> *C) As described in Tab 8, a declining block energy rate can be used in place of a demand charge; in these instances declining block energy rates should not be viewed as rate discounts for using more energy but rather as serving as an alternate means of recovering demand-related costs. This is the case for Manitoba Hydro's rates for GSS and GSM customers where a portion of demand costs (first 50 kVA) are recovered via energy charges which serves to phase in the demand charge as customers get larger. Manitoba Hydro believes the declining block rate provides an appropriate price signal to reflect the cost of providing service and does not believe it materially impacts the Corporation's ability to respond to the potential of either lower average usage or decarbonization.*

[487] GSS-GSM-5, Written Intervener Evidence, Dustin Madsen, Emrydia Consulting Corporation, April 3, 2023, page 95; Transcript June 2, 2023, page 2911; PUB/GSS-GSM I-8.

D) As defined in Tab 8, the ratemaking objective of efficiency considers whether price signals correspond with underlying embedded and / or marginal costs. Manitoba Hydro believes that the declining block rate design achieves this objective as the first two blocks capture the residual customer and demand-related costs that are not embedded in the basic monthly charge leaving the tail block, which will apply to most of the customers' marginal usage, to be priced more closely to the variable cost of energy.

I agree with Manitoba Hydro that as long as the first two blocks capture residual customer and demand-related costs, there would be a proper price signal, and if the final block is "priced more closely to the variable cost of energy", then there should be no improper price signal that encourages more consumption."

Mr. Madsen was also supportive of further evaluation of the rate design for the GSM rate class, including the possibility of flattening the energy component of the rate as discussed in Section 8.7.5 of Tab 8:

"I'm also supportive of pursuing innovations in the future to address the balance of fixed and variable costs, including further consideration of the declining block energy structure. Such design changes are complex and warrant a detailed discussion and assessment over time. Collaboration between Manitoba Hydro and the GSS/GSM rate class representatives is strongly encouraged." [488]

19.7.2. General Service Large Classes

As discussed throughout Section 8.8 of Tab 8 of the Application, Manitoba Hydro has prioritized a rebalancing between energy and demand charges which will increase costs recovered on a fixed versus variable basis. To accomplish this, Manitoba Hydro is proposing to achieve the overall 2.1% increase to the GSL 750V-30 kV class and the

[488] Transcript June 2, 2023, pages 2911-2912.

1.5% increase to the GSL 30-100kV and >100kV classes in both test years by increasing the demand rate only, with no increase being proposed to the energy rate. This approach will bring the revenue recovery proportion more in line with cost allocation and also recognizes that it is anticipated that additional resources will be needed to meet capacity requirements before additional resources are required to meet energy requirements.

In addition, for the 2024/25 fiscal year, Manitoba Hydro is proposing to refine the definition of billing demand for GSL classes with interval metering (GSL 30-100kV and GSL >100kV) by introducing a "peak" and "non-peak" consideration to the definition of billing demand based on when Manitoba Hydro experiences its system peak. The change in definition will result in customers' billing demand being the same or less than under the current definition. Manitoba Hydro estimates that demand billing determinants will be reduced to approximately 98.9% of billing demand under the current definition, which results in a reduction in demand revenue recovery of approximately $0.9 million (approx. 1.1% of total demand revenue). Manitoba Hydro proposes to recover the revenue shortfall through a slight increase to the demand charge (10 cents per kVA for the GSL 30-100kV class and 9 cents per kVA for the GSL >100kV class) to maintain revenue neutrality and recover the entirety of the revenue requirement. This change is anticipated to have negligible bill impacts for most customers in these classes.

With the exception of the items discussed below, no other intervener expressed issues or concerns with respect to Manitoba Hydro's rate design proposals for the General Service Large classes.

<u>Billing Demand Definition</u>

In his evidence, Mr. Bowman endorses the proposed change to the billing demand definition to be based on on-peak demand by noting that "*this is a small but important improvement in the price signal to these customers*."[489] However, while Mr. Bowman supports the change, he rejects Manitoba Hydro's proposal to implement the change on a revenue-neutral basis for the class on account of the high RCC outcomes for the GSL 30-100kV and >100kV classes:

[489] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 60, PDF page 63.

> *"The change to industrial rates to recognize on-peak demand rather than demand at any time is an improvement to the price signals and should be approved. There is no need to further adjust the demand charge for the approximately 1% in lost revenue when the industrial classes are already paying well above costs."* [490]

Changes to rate design may from time to time change the way costs are recovered and from which classes they are recovered, but do not change the overall amount of revenue that needs to be recovered. This point was reinforced by Ms. Van Hussen:

> *"When it comes to rate design, we often use the term 'revenue neutral'. What we mean by that, is that changes to rate design may change the way costs are recovered and the amount recovered from each class, but they do not change the overall amount of revenue that needs to be recovered. So, if we go back to our pie example, rate design can't change the size of the pie. And this is an important concept that applies to both parts of the rate design phase discussed by Ms. Gregorashuk.*
>
> *When we cut the pie and determine the proposed rate differentiation for the class and also when we determine how that rate increase is going to be applied to each of the rate structure components, we need to make sure our rate design changes are revenue neutral and aren't trying to change the size of the pie."* [491]

Once the revenue responsibility of a class and the average increase for the class have been established, Manitoba Hydro must determine the manner by which the allocated revenue requirement will be recovered. Given that the proposed change to the definition of billing demand results in a reduction of approximately $1 million to the revenue allocated to the class, the revenue shortfall must be made up by increasing standard rates in order for Manitoba Hydro to remain revenue neutral. Doing otherwise would be contrary to the rate making objective of full recovery of the revenue requirement (in other words, Mr. Bowman is suggesting a reduction in the

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[490] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 62, PDF page 65.
[491] Transcript June 6, 2023, pages 3410-3411.

size of the pie) or would require that the revenue shortfall be explicitly collected from other customer classes.

Moreover, Manitoba Hydro's proposal to recover the revenue shortfall through the demand charge enhances price signals by promoting a rebalancing between demand and energy charges, thereby enhancing price signals with respect to the increased importance of capacity in system planning.

In addition to concerns regarding the recovery of the revenue shortfall, Mr. Bowman has indicated that the 90% provision in the definition of billing demand is unjustified and should not be incorporated at this time.[492]

Manitoba Hydro is proposing to change the definition of billing demand to be based on the greatest of measured demand during peak hours, or 90% of measured demand during non-peak hours. The 90% provision effectively means that if a customer's demand during non-peak hours is less than 11% above the on-peak measured demand, then the customer would be saving on demand charges by shifting usage to non-peak hours. In his evidence, Mr. Bowman refers to the 90% provision as the "10% off-peak cap above on-peak load."[493]

Mr. Bowman suggests that the 10% cap unnecessarily limits uptake and potential benefits of industrial customers implementing load shifting and that a significant on-peak to off-peak load swing is unlikely.[494] Mr. Bowman further notes that "[i]n the event of some hypothetical abuse of the rate schedule by customers in future (if that were even possible) mitigation measures can be considered at that time" and concludes that "the 10% cap on off-peak usage is not justified at this time."[495]

As discussed in the response to MIPUG/MH I-110 and MIPUG/MH I-111, the inclusion of a provision for billing demand based on 90% of measured demand in non-peak hours is a measure of prudency and serves to avoid potential unintended consequences to Manitoba Hydro's system and / or costs, of unchecked load growth in hours defined as non-peak, that is unlikely but still possible. It is also consistent with

[492] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 62, PDF page 65.
[493] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 61, PDF page 64.
[494] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, pages 61-62, PDF pages 64-65.
[495] MIPUG-6, InterGroup Intervener Evidence, April 3, 2023, page 62, PDF page 65.

the practice of other jurisdictions that have similarly time-structured demand rates.[496] While Manitoba Hydro does not expect the billing demand definition to result in a material change to the existing load shape, especially in the short-term, it could have a more direct effect on future loads (e.g., new customers locating in Manitoba and existing customers looking to expand operations may consider how to strategically minimize their demand charges based on the time periods in the billing demand definition).

As indicated by Ms. Van Hussen, it is necessary to incorporate a cap to avoid unmitigated load growth during non-peak hours where customers are not paying their share of any capacity costs. However, there is discretion as to what the appropriate percentage for the cap should be:

> *"MS. MARNIE VAN HUSSEN: … We are mindful of the potential of new customers coming in or, you know, load growth outside of those peak hours. Those peak hours are, you know, a good indication of when the -- the peak typically happens. There's nothing -- there's no magic about that hour to say that if you peak in the next hour, you're not going to set a new system peak. So we're certainly mindful that we don't want to have, sort of, unmitigated load growth in those non-peak hours where customers are not paying a share of capacity costs. That's ultimately what it is, is we would have customers that are coming in, using the system without paying a share of capacity costs.*
>
> *MR. SVEN HOMBACH: You're aware of Mr. Bowman's evidence that it would be helpful to not have the 90 percent limit, right?*
>
> *MS. MARNIE VAN HUSSEN: I am aware.*
>
> *MR. SVEN HOMBACH: Would it be feasible for Manitoba Hydro to dip its feet into the water just a little more deeply and move beyond 90 (ninety) to, let's say, eighty (80) or seventy-five (75)?*

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[496] MH-1, Application Tab 8, Appendix 8.12.

MS. MARNIE VAN HUSSEN: I think that's fair. They're certainly in our jurisdictional analysis in Appendix 8.12. Thank you. We do see that a couple of the other jurisdictions do have something closer to a 75 or 80 percent non-peak hour definition. So, you know, I don't think that that would make or break our proposal for the -- the billing demand definition change." [497]

Manitoba Hydro argues that the inclusion of a non-peak demand provision is consistent with its flexibility rate objective, and it is prudent to include a reasonable limit to reduce the likelihood that the proposal would need to be unwound or reversed in the future due to some unforeseen changes in customer usage.

Bill Impacts of Rate Rebalancing

While Mr. Bowman appears to support Manitoba Hydro's implementation of the average rate increase through increases to the demand charge in order to improve price signals, he was critical of the bill impact outcomes, noting that some customers in the GSL classes will experience bill impacts above the overall general revenue increase of 2%:

"MR. PATRICK BOWMAN: … And I would put the image of the balance there so that the Board could focus on where balance really comes into this. Hydro's proposing that the entire rate increase for the industrials come on the demand charge, none on the energy charge.

That is appropriate from a price signal perspective. That is appropriate from implementing marginal costs. That's the right way to use marginal costs within a class's rate design. That will help encourage efficiency, but, at the same time, it will drive differential customer rate impacts.

That's where the balance comes in. Can we really do that without having some customers benefit more than is appropriate and some have to pay a greater-than-average rate increase?

[497] Transcript June 6, 2023, pages 3472-3473.

And normally, you know, this isn't a giant difference -- differential impact. I think the Board -- Hydro did provide the Bill impacts, but it does lead to certain industrial customers actually facing an above-average increase.

And I think that's very hard to -- not -- not above average for the class; above average for the Company, more than 2 percent. I think they go up to 2.4, if I remember correctly. It's a bit hard to understand how you could -- how -- how someone in a class that's overpaying by 13 or 14 percent could be told, oh, yeah, but your rate is going up more than average. I mean, that -- that's the trick.

And so, when we talk about rate design balance, that's the type of matter that -- that brings in this discretion in balance, not how we carve out the pie." [498]

While Manitoba Hydro acknowledges that there will be a differential impact on customers arising from its rate design proposals, Manitoba Hydro would also argue that revenue neutral rate design will always result in outcomes that are more beneficial for some customers than others. Generally, customers with low load factors will be more impacted by the proposed rate design changes for the GSL classes in this Application. However, Manitoba Hydro did consider the anticipated bill impacts in determining the pace of these changes.

As discussed in PUB/MH I-145, the combined bill impact of the proposed rate design changes effective April 1, 2024 is estimated to range from -0.5% to 2.4% for all customers in the GSL 30-100kV and >100kV classes. Most customers in these two classes (90%) are expected to experience a bill increase between 1.0% and 2.0%. In this Application, Manitoba Hydro has prioritized the rate objective of affordability (i.e., consideration was given to the magnitude of bill impacts created by rate design changes). The determination of reasonableness considers whether any particular customer is expected to experience a bill impact that is significantly above the average increase for the class. Manitoba Hydro is proposing a phased approach to rate

[498] Transcript June 9, 2023, pages 4009-4010.

rebalancing in order to moderate the bill impacts from increases to the demand charge, and the change to the definition of billing demand is expected to have negligible bill impacts for most customers. The refinement to the definition of billing demand will also provide customers with the opportunity to manage their bills in a relatively low-risk manner by shifting usage to off-peak hours to the extent possible, which is an opportunity that does not currently exist under the existing rate design. Moreover, the estimated range of bill impacts are below the current rate of inflation and the proposed rate increases are among the lowest in Canada compared to what other vertically integrated utilities are implementing, which supports the continued competitiveness of Manitoba Hydro's rates. Likewise, the rate differential of 0.5% below the average increase of 2.0% recommended for the two largest GSL classes in this Application, provides an opportunity to advance much needed changes to rate design to enhance price signals and lay the foundation to provide flexibility to implement changes in the future that may arise from the evolving energy landscape. Furthermore, because the rate design proposals in this application better align rates with how customers cause costs to be incurred, and the impact of the changes depend upon each customers' individual usage characteristics, the resulting bill impacts reflect a reduction in the cross-subsidy between customers within the GSL classes.

19.7.3. Other Rate Design Matters

In this Application, Manitoba Hydro is seeking approval to remove the Cooking and Heating Standard and Cooking and Heating Seasonal rates from Manitoba Hydro's Rate Schedule[499] as discussed in Section 8.7.6 of Tab 8 of the Application. These rates no longer have customers billing on them and have not been available for new services since 1976.

Manitoba Hydro is also seeking final approval of Light Emitting Diode rates for the Area and Roadway Lighting class approved on an interim basis in Order 150/20, and approval of additional new High Mast lighting rates for situations that do not represent the typical lighting installations but are required to ensure an approved rate is available for all potential configurations, as discussed in Section 8.9.2 of Tab 8 of the Application.

[499] MH-1, Application Tab 8, Appendices 8.4 and 8.7.

While this subject was ruled out of scope for oral evidence, no intervener raised any objections or provided evidence with regard to the above requests.

19.7.4. Curtailable Rates Program

Manitoba Hydro is proposing changes to the Terms and Conditions of the Curtailable Rates Program ("CRP"), which have been outlined in Section 8.11 of Tab 8 of the Application, and in Appendix 8.13. Manitoba Hydro is also seeking final approval of interim Orders issued by the PUB with respect to the CRP annual reference discounts listed in Appendix 9.1 and any further orders issued subsequent to the filing of the Application and prior to the PUB's order on this matter.

The CRP provides Manitoba Hydro with curtailable load as a resource to meet planning and operating reserves as well as energy supply requirements. Manitoba Hydro is proposing the following minor changes to the CRP:

- A new provision for annual testing of Option A and Option R, in order to ensure that CRP participants are prepared to respond to a curtailment call in the timeframe required and that they are able to shed the entire load nominated as curtailable upon request by Manitoba Hydro;
- Increasing the maximum number of curtailments for Option A from 15 to 16, which would bring the number of curtailments in line with the requirements of similar programs in neighbouring jurisdictions;
- Modified provisions to convert to firm service to align with the shortest timeframe required for Manitoba Hydro to obtain replacement firm capacity bilaterally from an external source; and
- Minor editorial changes.

In the responses to PUB/MH I-153a-d, Manitoba Hydro provided more details regarding the proposed requirement for annual testing, and in MIPUG/MH I-95, Manitoba Hydro explained how the proposed changes will provide value to both CRP and all of Manitoba Hydro's customers.

While this subject was ruled out of scope for oral evidence, no intervener raised any issues or objections with respect to the proposed changes to the Terms and Conditions and final approval of interim PUB Orders regarding the CRP reference discounts. As such, Manitoba Hydro requests that the PUB endorse the proposed changes to the CRP with an effective date of September 1, 2023.

During the industrial customer presentations on May 16, 2023, one customer indicated no concerns with the current design of the program,[500] while another customer indicated that they would like Manitoba Hydro to offer demand reduction options where a customer is paid a stand-by fee to be interruptible as needed and that they would like to participate in the CRP but the program is currently closed.[501] Mr. Bowman recommends that Manitoba Hydro "continue to move more optionality in rates for large customers, things like time of use, things like greater availability of curtailable."[502]

As discussed in the CRP Annual Report for 2021/22,[503] Manitoba Hydro is reviewing the CRP with the intent of identifying potential improvements or additional offerings that could provide further value to both customers and Manitoba Hydro. Manitoba Hydro has also started engagement with customers on their interests and needs regarding alternative rate options and plans to continue this engagement as outlined in Section 8.12 of Tab 8 of the Application. This includes engaging customers to define more specifically, potential peak load shaving opportunities and design parameters of interruptible and curtailable options, and to explore other options identified by customers.

19.7.5. Surplus Energy Program

In this Application, Manitoba Hydro is proposing to update the notice to interrupt provisions in the Terms and Conditions of the Surplus Energy Program ("SEP"). Manitoba Hydro is also seeking final approval of interim Orders issued by the PUB with respect to weekly SEP rates listed in Appendix 9.1 and any further orders issued subsequent to the filing of the Application and prior to the PUB's order on this matter.

[500] Transcript May 16, 2023, page 469.
[501] Transcript May 16, 2023, pages 485-486. Manitoba Hydro wishes to clarify that the program is not closed but rather under the existing Terms and Conditions, the amount of load that can be subscribed under Option A and Option R has been capped at 180MW and 50MW, respectively. Both of these options are largely subscribed, and as such, new load subscription cannot currently be accepted into these program options. There is currently no cap on Option E.
[502] Transcript June 9, 2023, page 4008.
[503] MH-1, Application, Tab 8, Appendix 8.15.

Under existing provisions, an SEP customer will be required to interrupt electricity supply to the SEP load within 36 hours of notice by Manitoba Hydro in one or more time-of-use periods specified in the notice. The current provision is insufficient for Manitoba Hydro to determine in a timely manner if an interruption of SEP load will be required and to provide notice to customers accordingly. As such, Manitoba Hydro is proposing to reduce the notice period from 36 hours to 12 hours to provide adequate time to determine if interruption of SEP load will be required to meet daily energy supply requirements in advance of the MISO Day-ahead market clearing. The proposed change is discussed in Section 8.11 of Tab 8 of the Application and outlined in Appendix 8.16.

As noted in the SEP Annual Report for the period November 1, 2020 to October 31, 2021 (Appendix 8.18) and discussed in Section 8.11 of the Tab 8 of the Application, Manitoba Hydro intends on reviewing the adequacy of the Terms and Conditions of the program to ensure pricing continues to reflect the value of the service being provided to customers and that non-participating customers are not adversely impacted. The timelines for completion of the review will be considered together with other priorities and at this time Manitoba Hydro anticipates the review to be completed when it files its next General Rate Application, as noted in PUB/MH I-155c. While the program is under review, Manitoba Hydro has suspended new enrollments in the SEP program to ensure that the interests of firm customers are fairly protected while continuing to serve long-standing SEP customers.

While there were a number of information requests related to the decision around interruption (PUB/MH I-158a-c, PUB/MH II-46, MIPUH/MH I-103a-b) and the rationale for undertaking a review of the program (MIPUG/MH I-99a-d, MIPUG/MH I-102, MIPUG/MH II-5a-c), no intervener raised any issues or objections with respect to the proposed change to the Terms and Conditions and final approval of interim PUB Orders regarding weekly SEP rates. As such, Manitoba Hydro requests that the PUB endorse the proposed changes to the SEP with an effective date of September 1, 2023. As noted in the response to PUB/MH I-156, Manitoba Hydro will be in contact with SEP customers as part of the review of the program, and it will endeavor to provide existing SEP customers with as much advance notice of a potential interruption as possible.

19.8. Position on Section 39.1(1) of the Act

The Chairman posed a question to Manitoba Hydro on whether s. 39.1(1) of *The Manitoba Hydro Amendment and Public Utilities Board Amendment Act* (the "Act") requires all customers to be within the zone of reasonableness when the PUB sets rates.[504]

Section 39.1(1) reads as follows:

> *"Electricity and rates policies*
> *39.1(1) It is hereby declared to be the policy of the government that*
>
> *(a) the rates charged by the corporation to each class of grid customers in Manitoba are to be based on the revenue requirements properly allocated to that class;*
> *(b) the rates charged to a class of grid customers in Manitoba are to be the same throughout the province;*
> *(c) subject to section 39.2 and the regulations, the rates charged by the corporation are to provide sufficient revenue*
> *(i) to enable the corporation to achieve the following target debt-to-capitalization ratios:*
> *(A) 80% by March 31, 2035,*
> *(B) 70% by March 31, 2040, and*
> *(ii) to achieve or maintain any additional financial targets established by regulation; and*
> *(d) subject to the policy objectives set out in clauses (a) to (c) and to the extent practicable, rates or changes in rates should be stable and predictable from year to year."*

The Act includes new definitions for "rate period" and "revenue requirement", among others, at s. 39(1):

> ***"rate period"*** *means the period of three consecutive fiscal years of the corporation beginning*

[504] Transcript June 7, 2023, pages 3682-3684.

(a) on April 1, 2025; or
(b) on the day immediately following the end of the previous rate period.

***"revenue requirement"**, in relation to a rate period, means the amount of rate revenue required in each fiscal year within the rate period*
(a) to pay the reasonable costs forecast by the corporation for that fiscal year, including
(i) the corporation's operating, maintenance and administrative expenses,
(ii) amounts in respect of capital expenditures,
(iii) debt service costs, and
(iv) power purchases, taxes, fees and other amounts required to be paid out of the corporation's revenue; and
(b) to achieve, in accordance with the regulations, the financial targets set out or referred to in subsection 39.1(1) and address material risks that could affect the achievement of those targets.

Reading the foregoing sections together, Manitoba Hydro submits that the government’s policy is that Manitoba Hydro should charge rates to each class of customers based, in part, on the revenue requirements of the utility, properly allocated to each class. That is not a fundamental change from how the PUB has been setting differentiated rates over the past few years in order to move customer classes into the zone of reasonableness. Manitoba Hydro, in its cost of service study, allocates or apportions its costs among its customer classes based on cost causation principles. Revenues that are within the zone of reasonableness are deemed to represent full cost recovery.

Manitoba Hydro submits that the purpose of s. 39.1(1), and s. 39.1(1)(a) in particular as it relates to the zone of reasonableness, is that by the end of each rate period (three consecutive fiscal years), customer classes should be within a zone of reasonableness (as defined by the PUB) in order to achieve proper cost recovery from rates.

Manitoba Hydro submits that this interpretation is also supported by sections 39(5) of the Act which states: 4. Subject to the policies set out in section 39.1, the corporation may propose changes to its cost allocation method or rate design, and the regulator may approve or disallow those changes or require the corporation to make other changes to them...”. In addition, section 39(6) of the Act permits the PUB to review the cost allocation method or rate design to be used in approving or varying rates for a rate period whether it be initiated by Manitoba Hydro or initiated by the PUB, in a separate process from the rate approval process.

20. CONCLUSION

In developing its application, Manitoba Hydro has focused on being open, transparent and helpful, aiming to build trust and confidence in the face of uncertainty, and has honored these principles throughout this review process.

The proposed rate increases in the 2023/24 and 2024/25 test years are amongst the lowest average increases projected by Manitoba Hydro in decades and provide customers with rate stability and predictability during a time when the cost of other goods and services are rapidly increasing.

The proposed rate increases in this Application form part of a plan that will ensure Manitoba Hydro can continue to meet customer expectations with respect to affordable, clean energy and safe, reliable service and become a financially healthy utility that Manitobans can continue to rely on for their energy needs now and in the future. Manitoba Hydro submits that its proposed rate increases are just, reasonable, and in the best interests of its customers.

1989 CarswellNat 586
Supreme Court of Canada

Bell Canada v. Canadian Radio-Television & Telecommunications Commission

1989 CarswellNat 586, 1989 CarswellNat 697, [1989] 1 S.C.R. 1722, [1989] A.C.S. No. 68, [1989] S.C.J. No. 68, 16 A.C.W.S. (3d) 1, 38 Admin. L.R. 1, 60 D.L.R. (4th) 682, 97 N.R. 15, J.E. 89-994, EYB 1989-67230

CDN. RADIO-TELEVISION & TELECOMMUNICATIONS COMM. v. BELL CAN. et al.

Lamer, Wilson, La Forest, L'Heureux-Dubé, Sopinka, Gonthier, and Cory JJ.

Heard: Febuary 21, 1989
Judgment: June 22, 1989
Docket: Doc. No. 20525

Counsel: *Raynold Langlois, Q.C.* , *Greg Van Koughnett* and *Luc Huppé* , for appellant.
Gérald Tremblay, Q.C. , and *Michel Racicot*, for respondent.
Graham Garton , for Attorney General of Canada.
Janet Yale , for Consumers' Association of Canada.
Kenneth Engelhart , for Canadian Business Telecommunications Alliance.
Michel Ryan , for C.N.C.P. Telecommunications
Andrew Roman and *Robert Horwood*, for National Anti-Poverty Organization.

The judgment of the Court was delivered by *Gonthier J.*:

1 The present case is an appeal against a decision of the Federal Court of Appeal [reported at (1987), [1988] 1 F.C. 296], which quashed one of the orders made by the appellant in Telecom Decision C.R.T.C. ["Decision"] 86-17. The impugned order compelled the respondent to distribute $206 million in excess revenues earned in the years 1985 and 1986 through a one-time credit to be granted to certain classes of customers. The respondent does not contest the factual findings on which Decision 86-17 is based, nor does it claim that this order would unduly prejudice its financial position. None of the other orders made in Decision 86-17 are challenged.

2 The appellant claims that the purpose of the challenged order was to provide telephone users with a remedy against interim rates, which turned out to be excessive, on the basis of the findings of fact made by the appellant following a final hearing, held in the summer of 1986, for the purpose of setting rates to be charged by the respondent in the years 1985 and following. These findings of fact are reported in Decision 86-17. Since this case turns on the proper characterization of the one-time credit order made in Decision 86-17, it is important to describe the procedural history of the administrative proceedings which led to the order now contested by the respondent.

I — The Facts

3 On March 28, 1984, the respondent applied for a general rate increase under Part VII of the C.R.T.C. Telecommunications Rules of Procedure, SOR/79-554 [under the *National Transportation Act* , R.S.C. 1985, c. N-20], which provides for a summary public process to deal with special applications. The respondent claimed that the Canadian Government's restraint program restricting rate increases of federally regulated utilities to 5 per cent and 6 per cent was sufficient justification to dispense with the normal procedure for general rate increase applications set out in Part III of the C.R.T.C. Telecommunications Rules of Procedure. In Decision 84-15, the appellant rejected this application on the ground that the respondent had failed to use the appropriate procedure as set out in Part III of these rules. However, the appellant indicated that if the respondent was to suffer

financial prejudice as a result of the delays involved in preparing for the more complex procedure set out in part III, it could always apply for interim relief pending a hearing and a decision on the merits, at pp. 8-9:

> The Commission recognizes that, in 1985 and beyond, in the absence of rate relief, a deterioration in the Company's financial position could occur. In this regard, if the Company should find it necessary to file an application for a general rate increase under Part III of the Rules, the Commission would be prepared to schedule a public hearing on such an application in the fall of 1985. *Should Bell consider it necessary to seek rate increases to come into effect earlier in 1985 than this schedule would allow, it may of course apply for interim relief* . In the event Bell were to seek such interim relief, it would be open to the Company to suggest that the Commission's traditional test for determining interim rate applications is overly restrictive in light of the Commission hearing schedule and to put forward proposals for an alternative test for consideration.

(Emphasis added.) On September 4, 1984, the respondent filed an application for a general rate increase based on 1985 financial data which would come into effect on January 1, 1986. At the same time, the respondent applied for an interim rate increase of 3.6 per cent.

4 In Decision 84-28, rendered on December 19, 1984, the appellant set out the following policy previously adopted in Decision 80-7 with respect to the granting of interim rate increases, at pp. 8-9:

> The Commission's policy concerning interim rate increases, enunciated in Decision 80-7, is as follows:
>
> The Commission considers that, as a rule, general rate increases should only be granted following the full public process contemplated by Part III of its Telecommunications Rules of Procedure. In the absence of such a process, general rate increases should not in the Commission's view be granted, even on an interim basis, except where special circumstances can be demonstrated. *Such circumstances would include lengthy delays in dealing with an application that could result in a serious deterioration in the financial condition of an applicant absent a general interim increase* .

(Emphasis added.) The respondent argued that its financial situation warranted an interim rate increase and did not question the reasonableness of this policy. The appellant agreed with the respondent's submission that, in the absence of interim rate increases, it might suffer from serious financial deterioration and awarded an interim rate increase of 2 per cent. In this decision, the appellant required the respondent to prepare for a hearing to be held in the fall of 1985 for the purpose of assessing the respondent's application for a final order increasing its rates on the basis of 2 test years, 1985 and 1986. Decision 84-28 also states the reasons why the interim rate increase was set at 2 per cent, at p. 10:

> In determining the amount of interim rate increases required under the circumstances, the Commission has taken into account the following factors:
>
> 1) While the company stated that an interest coverage ratio of 4.0 times is required, the Commission regards the maintenance of the coverage ratio of 3.8 times, projected by the Company for 1984, as sufficient for the purposes of this interim decision.
>
> 2) With regard to the level of ROE ['return on equity'], the Commission is of the view that, for 1985, *and subject to review in the course of its consideration of the Company's general rate increase application in the fall of 1985* , 13.7% is appropriate for determining the amount of rate increases to be permitted pursuant to this interim increase application.
>
> 3) With regard to the Company's 1985 expense forecasts, the Commission notes that the inflation factor used by the Company is higher than the current consensus forecast of the inflation rate for 1985 and considers that Bell's forecast of its 1985 Operating Expenses could be overestimated by approximately $25 million.
>
> Taking the above factors into account, the Commission has decided that an interim rate increase of 2% for all services in respect of which rate increases were requested by the Company in the interim application is appropriate at this time. This increase is expected to generate additional revenues of $65 million from 1 January 1985 to 31 December 1985. *To permit*

> *the review of the Company's 1985 revenue requirement by the Commission at the fall 1985 public hearing, Bell is directed to file its 4 June 1985 general rate increase application on the basis of two test years, 1985 and 1986* .

(Emphasis added.) The reasons set out in the appellant's decision indicate that the interim rate increase was calculated on the basis of financial information provided by the respondent without placing this information under the scrutiny normally associated with hearings made under Part III of the C.R.T.C. Telecommunications Rules of Procedure. Furthermore, the appellant clearly expressed the intention to review this interim rate increase in its final decision on the respondent's application for a general rate increase, on the basis of financial information for the years 1985 and 1986. Given the content of the appellant's final decision, it is also important to note that the 2 per cent interim rate increase was calculated on the assumption that the respondent's return on equity for 1985 should be 13.7 per cent subject to review in the final decision.

5 The respondent's financial situation later improved thereby reducing the necessity to proceed with an early hearing for the purpose of obtaining a general and final rate increase. By a letter dated March 20, 1985, the respondent asked for this hearing to be postponed to February 10, 1986, suggesting however that the 2 per cent interim increase be given immediate final approval. In C.R.T.C. Telecom Public Notice 1985-30 dated April 16, 1985, the appellant granted the postponement but refused to grant the final approval requested by the respondent without further investigation into this matter. The Commission added that it would monitor the respondent's financial situation on a monthly basis and ordered the filing of monthly statements, at p. 4:

> In view of the improving trend in the Company's financial performance, the Commission further directs as follows:
>
> Bell Canada is to provide to the Commission for the balance of 1985, within 30 days after the end of each month, commencing with April 1985, a full year forecast of revenues and expenses on a regulated basis for the year 1985, together with the estimated financial ratios including the projected regulated return on common equity.
>
> The Commission will monitor the Company's financial performance during 1985, *in order to determine whether any further rate action may be necessary* .

(Emphasis added.) Again, the appellant clearly expressed its intention to prevent abuse of interim rate increases.

6 After a review of the July financial information filing ordered in C.R.T.C. Telecom Public Notice 1985-30, the appellant asked the respondent to provide reasons why the interim rate increase of 2 per cent should remain in force given its improved financial situation. The respondent was unable to convince the appellant that this interim increase remained necessary to avoid financial deterioration and was accordingly ordered to file revised tariffs effective as of September 1, 1985, at pp. 4-5 of Decision 85-18:

> In view of the improving trend in Bell's financial performance, the Commission is satisfied that the company no longer needs the 2% interim increases *which were awarded in Decision 84-28 in order to avoid serious financial deterioration in 1985* . Accordingly, Bell is directed to file revised tariffs forthwith, with an effective date of 1 September 1985, to suspend these increases.
>
> In arriving at its decision the Commission has estimated that, *with interim rates in effect for the complete year* , the company would earn an ROE ['return on equity'] of approximatively 14.5% in 1985, *a return well in excess of the 13.7% considered appropriate for determining the 2% interim rate increases* . The Commission also projected that interest coverage would be approximately 3.9 times. This would improve on the actual 1984 coverage of 3.8 times. These estimates are not significantly different from Bell's current expectation of its 1985 result.
>
> *The Commission will make its final determination of Bell's revenue requirement for the year 1985 in the general rate proceeding currently scheduled to commence with an application to be filed on 10 February 1986* .

(Emphasis added.) As a result of this decision, the respondent was forced to charge the rates effective before its application for a rate increase, filed on March 28, 1984. However, even though the rates effective as of September 1, 1985 were numerically identical to the rates in force under the previous final decision prior to the interim increase, these new rates remained interim in nature. In fact, the appellant reiterated its intention to review the rates actually charged during 1985 and 1986.

7 On October 31, 1985, the respondent decided not to proceed with its application for a general rate increase and requested that its procedures be withdrawn. In C.R.T.C. Telecom Public Notice 1985-85, the appellant decided to review the respondent's financial situation and therefore the appropriateness of its rates, notwithstanding its request to withdraw its initial application for a general rate increase, at pp. 3-4:

> *In light of these forecasts and the degree to which the company's rate structure is expected to be considered in separate proceedings, Bell stated that it wished to refrain from proceeding with the application schedule to be filed on 10 February 1986* . Accordingly, the company requested the withdrawal of the amended Directions on Procedure issued by the Commission in Public Notice 1985-30.
>
> . . . . .
>
> The Commission notes that the appropriate rate of return for Bell has not been reviewed in an oral hearing since the proceeding which culminated in *Bell Canada — General Increase in Rates* , Telecom Decision CRTC 81-15, 20 September 1981 (Decision 81-15). *The Commission considers that, given Bell's current forecasts, it would be appropriate to review the company's cost of equity for the years 1985, 1986 and 1987 in the proceeding scheduled for 1986* . Such a review would allow consideration of the changing financial and economic conditions since Decision 81-15 and the impact of Bell's corporate reorganization on its rate of return. The Commission notes that other issues arising from the reorganization would also be addressed in the 1986 proceeding.

(Emphasis added.) This interim decision indicates that the appellant wished to continue the original rate review procedure initiated by the respondent in March 1984. Thus, the rates in force as of January 1, 1985 until the final decision now challenged by the respondent were interim rates subject to review.

8 The hearing which led to the final decision lasted from June 2 to July 16, 1986 and this final decision, Decision 86-17, was rendered on October 14, 1986. In this decision, the appellant first established appropriate levels of profitability for the respondent on the basis of its return on equity. The appellant then calculated the amount of excess revenues earned by the respondent in 1985 and 1986, along with the necessary reduction in forecasted revenues for 1987. It was found that the respondent had earned excess revenues of $63 million in 1985 and $143 million in 1986, for a total of $206 million, at p. 93:

> After making further adjustments for the compensation for temporarily transferred employees and including the regulatory treatment for non-integral subsidiary and associated companies, the Commission has determined that a revenue requirement reduction of $234 million would provide the company with a 12.75% ROE ['return on equity'] on a regulated basis in 1987. Similarly, the Commission has determined that $143 million is the required revenue reduction to achieve the upper end of the permissible ROE on a regulated basis in 1986, 13.25%. With respect to 1985, after making the adjustments set out in this decision, the Commission has determined that Bell earned excess revenues in the amount of $63 million, the deduction of which would provide 13.75%, the upper end of the permissible ROE on a regulated basis.

It is important to note that the evidence and the arguments presented by the interested parties as well as interveners were carefully scrutinized by the appellant, at pp. 77-92 of Decision 86-17. It is for all practical purposes impossible to engage in such a meticulous and painstaking analysis of all relevant facts when faced with an application for interim relief. Finally, it is also useful to note that the permissible return on equity of 13.7 per cent allowed by the appellant in its interim decision, Decision 84-28, was increased to 13.75 per cent in Decision 86-17. Thus, the appellant realized that the interim rates approved for 1985 yielded greater rates of return than initially anticipated, and that the rate of return actually recorded for that year even exceeded the greater allowable rate of return fixed in the final decision, Decision 86-17. Such differences between projected and actual rates of return are common and certainly call for a high level of flexibility in the exercise of the appellant's regulatory duties.

9 The Commission decided that the respondent could not retain excess revenues earned on the basis of interim rates and issued the order now challenged by the respondent in order to provide a remedy for this situation. This order reads as follows, at pp. 95-96:

> *Concerning the excess revenues for the years 1985 and 1986, the Commission directs that the required adjustments be made by means of a one-time credit to subscribers of record, as of the date of this decision, of the following local services* : residence and business individual, two-party and four-party line services; PBX trunk services; centrex lines; enhanced exchange-wide dial lines; exchange radio-telephone service; service-system service and information system access line service. *The Commission directs that the credit to each subscriber be determined by pro-rating the sum of the excess revenues for 1985 and 1986 of $206 million in relation to the subscriber's monthly recurring billing for the specified local services provided as of the date of this decision* . The Commission further directs that the work necessary to implement the above directives be commenced immediately and that the billing adjustments be completed by no later than 31 January 1987. Finally, the Commission directs the company to file a report detailing the implementation of the credit by no later than 16 February 1987.
>
> *The Commission considers that 1987 excess revenues are best dealt with Gthrough rate reductions to be effective 1 January 1987* .

(Emphasis added.) Although the respondent always charged rates approved by the appellant, the appellant found it necessary to make sure that its assessment of allowable revenues for 1985 and 1986 would be complied with. The appellant argues that the order now challenged by the respondent was the most efficient way of redistributing these excess revenues to the respondent's customers even though they would not necessarily be refunded to those who actually had to pay the rates in force during that period.

10 It is therefore obvious that the appellant only allowed interim rates to be charged after January 1, 1985 on the assumption that it would review these rates in a hearing to be held in order to deal with an application for a general rate increase. Every interim decision which led to Decision 86-17 confirmed the appellant's intention to review the interim rates at the final hearing. Finally, the interim rates were ordered for the purpose of preventing any serious deterioration in the respondent's financial situation while awaiting for a final decision on the merits. Of necessity, these interim rates were determined on the basis of incomplete evidence presented by the respondent. It cannot be said that the purpose of the interim rate increase ordered by the appellant was to serve as a temporary final decision.

II — The Issue and the Arguments Raised by the Parties

11 In this Court, as well as in the Federal Court of Appeal, the parties have agreed that the only issue arising out of the facts of this case is whether the appellant had jurisdiction to order the respondent to grant a one-time credit to its customers. The appellant's findings of fact, its determination with respect to the respondent's revenue requirements for 1985 and 1986, and its computation of the amount of excess revenues earned during this period are not contested by the respondent. In my opinion, this issue can be divided in two subquestions:

> 1. Whether the appellant had the legislative authority to review the revenues made by the respondent during the period when interim rates were in force;
>
> 2. Whether the appellant had jurisdiction to make an order compelling the respondent to grant a one-time credit to its customers.

12 The main arguments raised by the appellant can be summarized as follows:

> 1. The *Railway Act* , R.S.C. 1985, c. R-3 and the *National Transportation Act* , R.S.C. 1985, c. N-20 grant the appellant the power to review the period during which a regulated entity was allowed to charge interim rates, for the purpose of comparing the revenues earned during this period to the appropriate level of revenues set in the final decision;
>
> 2. The power to make a one-time credit order is necessarily ancillary to the power to review the period during which interim rates were charged, and the appellant has jurisdiction to determine the most efficient method of providing a remedy in cases where excess revenues were made.

13 The main arguments raised by the respondent can be summarized as follows:

1. The power to set tolls and tariffs does not include the power to review and make orders with respect to the respondent's level of revenues;

2. The appellant has no power to make a one-time credit order with respect to revenues earned as a result of having charged rates which the respondent, by virtue of the *Railway Act* , was obliged to charge, whether these rates were set by an interim order or by a final order.

14 Counsel for the National Anti-Poverty organization ("N.A.P.O.") has also argued that the appellant's decisions concerning the interpretation of statutes which grant them jurisdiction to deal with certain matters are entitled to curial deference and cannot be reviewed unless they are patently unreasonable. This argument raises the issue of the scope of review allowed by s. 68(1) of the *National Transportation Act* and must be dealt with prior to any analysis of the relevant statutory provisions claimed to be the source of the appellant's jurisdiction to make the one-time credit order found in Decision 86-17.

15 The present case raises difficult questions of statutory interpretation and it will therefore be necessary to examine the relevant provisions of the *wRailway Act* and the *National Transportation Act* before moving to a detailed analysis of the decision of the Federal Court of Appeal and the arguments raised by the parties.

III — Relevant Legislative Provisions

16 The appellant derives its power to regulate the telephone industry from ss. 334 to 340 of the *Railway Act* ("Provisions Governing Telegraphs and Telephones") and from ss. 47 et seq. of the *National Transportation Act* ("General Jurisdiction and Powers in Respect of Railways"). The *Railway Act* sets out the general criteria concerning the setting of rates and tariffs to be charged by telephone utility companies, whereas the *National Transportation Act* sets out the appellant's procedural powers in the context of decisions concerning, amongst other matters, telephone rates and tariffs.

17 Sections 335(1), 335(2) and 335(3) of the *Railway Act* (formerly ss. 320(2) and 320(3)) state the principle upon which the appellant's regulatory authority rests, namely, that telephone rates and tariffs are subject to approval by the appellant, cannot be changed without its prior authorization, and may be revised at any time by the appellant:

> 335. (1) Notwithstanding anything in any other Act, all telegraph and telephone tolls to be charged by a company, other than a toll for the transmission of a message intended for reception by the general public and charged by a company licensed under the *Broadcasting Act, are subject to the approval of the Commission, and may be revised by the Commission from time to time* .
>
> (2) The company shall file with the Commission tariffs of any telegraph or telephone tolls to be charged, and the tariffs shall be in such form, size and style, and give such information, particulars and details, as the Commission by regulation or in any particular case prescribes.
>
> (3) *Except with the approval of the Commission, the company shall not charge and is not entitled to charge any telegraph or telephone toll in respect of which there is default in filing under subsection (2), or which is disallowed by the Commission ...*

(Emphasis added.) The most important requirement governing the appellant's power to set telephone rates is found in s. 340(1) of the *Railway Act* which provides that all such rates must be "just and reasonable":

> 340. (1) *All tolls shall be just and reasonable* and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.

(Emphasis added.) Section 340 also prohibits discriminatory telephone rates and gives the appellant the power to suspend, postpone, or disallow a tariff of tolls which is contrary to ss. 335 to 340 and substitute a satisfactory tariff of tolls in lieu thereof.

18 Finally, s. 340(5) of the *Railway Act* gives the appellant the power to make orders with respect to traffic, tolls and tariffs in all matters not expressly covered by s. 340:

> 340....
>
> (5) In all other matters not expressly provided for in this section, the Commission may make orders with respect to all matters relating to traffic, tolls and tariffs or any of them.

Although the power granted by s. 340(5) could be construed restrictively by the application of the ejusdem generis rule, I do not think that such an interpretation is warranted. Section 340(5) is but one indication of the legislator's intention to give the appellant all the powers necessary to ensure that the principle set out in s. 340(1), namely that all rates should be just and reasonable, be observed at all times.

19 Sections 47 et seq. of the *National Transportation Act* set out, from a procedural point of view, the appellant's jurisdiction with respect to the powers granted by the *Railway Act* . Section 49(1) gives the appellant jurisdiction over all complaints concerning compliance with the Act, while s. 49(3) gives the appellant jurisdiction over all matters of fact or law for the purposes of the *Railway Act* and of ss. 47 et seq. of the *National Transportation Act* . However, s. 68(1) provides an appeal to the Federal Court of Appeal, with leave, on any question of law or jurisdiction, and it is under this provision that the respondent has challenged Decision 86-17.

20 In many respects, ss. 47 et seq. of the *National Transportation Act* have been designed to further the policy objectives and the regulatory scheme set out in the *Railway Act* governing the approval of telephone rates and tariffs. Thus, s. 52 of the *National Transportation Act* gives the appellant the power to inquire into, hear or determine, of its own motion or upon request from the Minister, any matter which it has the right to inquire into, hear or determine under the *Railway Act* :

> 52. The Commission may, of its own motion, or shall, on the request of the Minister, inquire into, hear and determine any matter or thing that, under this part or the *Railway Act* , it may inquire into, hear and determine upon application or complaint, and with respect thereto has the same powers as, on any application or complaint, are vested in it by this Act.

Section 52 is therefore the corollary of the appellant's power to "revise [tolls] ... from time to time" found in s. 335(1) of the *Railway Act* . Thus, the appellant has the power to review, from time to time, its own final decisions on a proprio motu basis. Similarly, s. 61 provides that the appellant is not bound by the wording of any complaint or application it hears and may make orders which would otherwise offend the ultra petita rule:

> 61. On any application made to the Commission, the Commission may make an order granting the whole or part only of the application, or may grant such further or other relief, in addition to or in substitution for that applied for, as to the Commission may seem just and proper, as fully in all respects as if the application had been for that partial, other or further relief.

21 By virtue of s. 60(2) of the *National Transportation Act* , the appellant also has the power to make interim orders:

> 60. ...
>
> (2) The Commission may, instead of making an order final in the first instance, make an interim order and reserve further directions either for an adjourned hearing of the matter or for further application.

22 Finally, by virtue of s. 66 of the *National Transportation Act* , the appellant has the power to review any of its past decisions, whether they are final or interim:

> 66. The Commission may review, rescind, change, alter or vary any order or decision made by it or may re-hear any application before deciding it.

23 It is obvious from the legislative scheme set out in the *Railway Act* and the *National Transportation Act* that the appellant has been given broad powers for the purpose of ensuring that telephone rates and tariffs are, at all times, just and reasonable. The appellant may revise rates at any time, either of its own motion or in the context of an application made by an interested party. The appellant is not even bound by the relief sought by such applications, and may make any order related thereto provided that the parties have received adequate notice of the issues to be dealt with at the hearing. Were it not for the fact that the appellant has the power to make interim orders, one might say that the appellant's powers in this area are limited only by the time it takes to process applications, prepare for hearings and analyze all the evidence. However, the appellant does have the power to make interim orders and this power must be interpreted in light of the legislator's intention to provide the appellant with flexible and versatile powers for the purpose of ensuring that telephone rates are always just and reasonable.

24 The question before this Court is whether the appellant has the statutory authority to make a one-time credit order for the purpose of remedying a situation where, after a final hearing dealing with the reasonableness of telephone rates charged during the years under review, it finds that interim rates in force during that period were not just and reasonable. Since there is no clear provision on this subject in the *Railway Act* or in the *National Transportation Act* , it will be necessary to determine whether this power is derived by necessary implication from the regulatory schemes set out in these statutes.

IV — The Decision of the Court Below

25 In the Federal Court of Appeal, the respondent in this Court argued that in order to find statutory authority for the power to make a one-time credit order, it was necessary to find that s. 66 (power to "review, rescind, change, alter or vary" previous decisions) or s. 60(2) (power to make interim orders) of the *National Transportation Act* provide powers to make retroactive orders. Of course, the respondent argued that these provisions did not grant such a power and the majority of the Federal Court of Appeal, composed of Marceau and Pratte JJ. agreed with this argument, Hugessen J. dissenting.

26 Marceau J. held that the appellant in this Court only had the power to fix telephone tolls and tariffs, and that it has no statutory authority to deal with excess revenues or deficiencies in revenues arising as a result of a discrepancy between the rate of return yielded from the interim rates in force prior to the final decision and the permissible rate of return fixed by this final decision. Marceau J. was of the opinion that the wording of s. 66 of the *National Transportation Act* is neutral with respect to retroactivity, and that the presumption against retroactivity should therefore operate. Marceau J. added that the power to make interim orders does not carry with it the power to remedy any discrepancy between interim and final orders because the respondent could not be forced to reimburse revenues earned by charging rates approved by the appellant. Thus, according to Marceau J., the regulatory scheme set out in the *Railway Act* and the *National Transportation Act* is prospective in nature and, in the context of such a scheme, the power to make interim orders only involves the power to make orders "for the time being".

27 Pratte J., who concurred in the result with Marceau J., rejected all arguments based on the retroactive nature of the powers granted by ss. 60(2) and 66 of the *National Transportation Act* . Pratte J. was of the opinion that the impugned order was not retroactive in nature since its effect was to force the respondent to grant a credit in the future rather than change the rates charged in the past in a retroactive manner. Pratte J. then stated that if legislative authority existed for Decision 86-17, it must be found in s. 60(2) of the *National Transportation Act* which provides for "further directions" to be made at a later date following an interim decision. However, Pratte J. was of the opinion that any "further direction" must be in the nature of an order which can be made under s. 60(2) in the first place. It follows from that reasoning that if no one-time credit order can be made by interim order, no "further direction" to that effect can be made under s. 60(2). Pratte J. then agreed with Marceau J. that the respondent could not be forced to reimburse revenues made by charging rates approved by the appellant whether by interim order or by a "further direction" made in a final order.

28 Hugessen J. dissented on the basis that, within the statutory framework set out in the *Railway Act* and the *National Transportation Act* , all orders whether final or interim can, by virtue of ss. 60(2) and 66 of the *National Transportation Act* , be modified by a further prospective order; thus, the proposed rule that interim orders can only be modified by a further prospective order would, in Hugessen J.'s opinion, effectively eliminate any distinction between final and interim orders and defeat the legislator's intention to provide the appellant with a distinct and independent power to make interim orders. In order

to differentiate interim orders from final orders, Hugessen J. was of the opinion that the appellant in this Court must have the power to fix just and reasonable rates as of the date at which interim rates came into effect. Thus, only interim rates can be modified in a retrospective manner by a final order. Hugessen J. then stated that the interim rates in force in 1985 and 1986 must not be divided into the previous rate and the interim rate increase of 2 per cent: the resulting rate must be viewed as interim in its entirety because all the rates charged after January 1, 1985 were authorized by interim orders. Finally, Hugessen J. stated that the one-time credit order was a valid exercise of the power to set just and reasonable rates as of January 1, 1985 and that the choice of the appropriate remedy was an "'administrative matter' properly left for the Commission's determination". Hugessen J. also noted that the appellant's order was in substance, though not in form, a "matter relating to tolls and tariffs" within the meaning of s. 340(5) of the *Railway Act* .

V — Analysis

29

a) Curial deference towards the decisions of the C.R.T.C.

30 N.A.P.O. argues that the appellant's decisions are entitled to "curial deference" because of their national importance, and that these decisions should not be overturned unless they are patently unreasonable. N.A.P.O. cites the following cases as authority for this proposition: *N.B. Liquor Corp. v. C.U.P.E., Loc. 963*, [1979] 2 S.C.R. 227, 25 N.B.R. (2d) 237, 51 A.P.R. 237, 24 N.R. 341, 79 C.L.L.C. 14,209 ("C.U.P.E."); *Douglas Aircraft Co. of Can. Ltd. v. McConnell*, [1980] 1 S.C.R. 245, 29 N.R. 109, 23 L.A.C. (2d) 143n, 99 D.L.R. (3d) 385, (sub nom. *Douglas Aircraft Co. v. U.A.W., Loc. 1967)* 79 C.L.L.C. 14,221 ; *A.U.P.E. v. Bd. of Governors of Olds College*, [1982] 1 S.C.R. 923 ; *O.P.S.E.U. v. Forer* (1985), 52 O.R. (2d) 705, 15 Admin. L.R. 145, 12 O.A.C. 1, 23 D.L.R. (4th) 97 ; *Ottawa (City) v. Ottawa Professional Firefighters' Assn.* (1987), 58 O.R. (2d) 685, 24 Admin. L.R. 213, 19 O.A.C. 197, 36 D.L.R. (4th) 609 ; *McCreary v. Greyhound Lines of Can. Ltd.* (1987), 87 C.L.L.C. 17,018, 78 N.R. 192, 8 C.H.R.R. D/4184, 38 D.L.R. (4th) 724 (Fed. C.A.) ; and *Canadian Pacific Ltd. v. Canadian Transport Commn.* (1987), 79 N.R. 13 (Fed. C.A.) ("Canadian Pacific").

31 With the exception of the *Canadian Pacific* case, supra, all these cases involved judicial review of decisions which were either protected by a privative clause or by a provision stating that no appeal lies therefrom. Where the legislator has clearly stated that the decision of an administrative tribunal is final and binding, Courts of original jurisdiction cannot interfere with such decisions unless the tribunal has committed an error which goes to its jurisdiction. Thus, this Court has decided in the *C.U.P.E.* case, supra, that judicial review cannot be completely excluded by statute and that Courts of original jurisdiction can always quash a decision if it is "so patently unreasonable that its construction cannot be rationally supported by the relevant legislation and demands intervention by the court upon review" (p. 237, S.C.R.). Decisions which are so protected are, in that sense, entitled to a non-discretionary form of deference because the legislator intended them to be final and conclusive and, in turn, this intention arises out of the desire to leave the resolution of some issues in the hands of a specialized tribunal. In the *C.U.P.E.* case, Dickson J., as he then was, described the legislator's intention as follows, at pp. 235-36 (S.C.R.):

> Section 101 constitutes a clear statutory direction on the part of the Legislature that public sector labour matters be promptly and finally decided by the Board. Privative clauses of this type are typically found in labour relations legislation. The rationale for protection of a labour board's decisions within jurisdiction is straightforward and compelling. The labour board is a specialized tribunal which administers a comprehensive statute regulating labour relations. In the administration of that regime, a board is called upon not only to find facts and decide questions of law, but also to exercise its understanding of the body of jurisprudence that has developed around the collective bargaining system, as understood in Canada, and its labour relations sense acquired from accumulated experience in the area.

However, it is important to stress the fact that the decision of an administrative tribunal can only be entitled to such deference if the legislator has clearly expressed his intention to protect such decisions through the use of privative clauses or clauses which state that the decision is final and without appeal. As formulated, N.A.P.O.'s argument on curial deference must therefore be rejected because it fails to recognize the basic difference between appellate review and judicial review of decisions which do not fall within the jurisdiction of the lower tribunal.

32 Although s. 49(3) of the *National Transportation Act* provides that the appellant has full jurisdiction to hear and determine all matters whether of law or fact for the purposes of the *Railway Act* and of Part IV of the *National Transportation Act* , the appellant's decisions are subject to appeal, with leave, to the Federal Court of Appeal on questions of law or jurisdiction by virtue of s. 68(1), which reads as follows:

> 68. (1) An appeal lies from the Commission to the Federal Court of Appeal on a question of law or a question of jurisdiction on leave therefor being obtained from that Court on application made within one month after the making of the order, decision, rule or regulation sought to be appealed from or within such further time as a judge of that Court under special circumstances allows, and on notice to the parties and the Commission, and on hearing such of them as appear and desire to be heard.

It is trite to say that the jurisdiction of a Court on appeal is much broader than the jurisdiction of a Court on judicial review. In principle, a Court is entitled, on appeal, to disagree with the reasoning of the lower tribunal.

33 However, within the context of a statutory appeal from an administrative tribunal, additional consideration must be given to the principle of specialization of duties. Although an appeal tribunal has the right to disagree with the lower tribunal on issues which fall within the scope of the statutory appeal, curial deference should be given to the opinion of the lower tribunal on issues which fall squarely within its area of expertise. The *Canadian Pacific* case is an example of a situation where curial deference towards a decision of the Canadian Transport Commission involving the interpretation of a tariff was appropriate. The decision of the Canadian Transport Commission was appealed to a review committee and then to the Federal Court of Appeal. Urie J. held that the decision of the review committee must not be reversed unless it is unreasonable or clearly wrong, at pp. 16-17:

> On the appeal from that decision to this court, the appellant advanced essentially the same grounds and arguments which it had submitted to the R.T.C. As to the first ground, I am of the opinion that the R.T.C. correctly interpreted the two items from the tariff and since its view was confirmed by the Review Committee, that Committee did not commit an error in construction. No useful purpose would be served by my restating the reasons of the R.T.C. for interpreting the items as they did and I respectfully adopt them as my own. *This court should not interfere with an interpretation made by bodies having the expertise of the R.T.C. and the Review Committee in an area within their jurisdiction, unless their interpretation is not reasonable or is clearly wrong* . Neither situation prevails in this case.

(Emphasis added.) Although the very purpose of the review committee is to interpret the tariff, and although such questions of interpretation fall within the Review Committee's area of special expertise, it does not follow that its decisions can only be reviewed if they are unreasonable. However, the principle of specialization of duties justifies curial deference in such circumstances.

34 In this case, the respondent is challenging the appellant's decision on a question of law and jurisdiction involving the nature of interim decisions and the extent of the powers conferred on the appellant when it makes interim decisions. This question cannot be solved without an analysis of the procedural scheme created by the *Railway Act* and the *National Transportation Act* . It is a question of law which is clearly subject to appeal under s. 68(1) of the *National Transportation Act* . It is also a question of jurisdiction because it involves an inquiry into whether the appellant had the power to make a one-time credit order.

35 Except as regards the choice, amongst remedies available to the appellant, of the most appropriate remedy to achieve the goal of just and reasonable rates throughout the interim period, the decision impugned by the respondent is not a decision which falls within the appellant's area of special expertise and is therefore pursuant to s. 68(1), subject to review in accordance with the principles governing appeals. Indeed, the appellant was not created for the purpose of interpreting the *Railway Act* or the *National Transportation Act* but rather to ensure, amongst other duties, that telephone rates are always just and reasonable.

b) The power to regulate Bell Canada's revenues

36 The respondent argues that the appellant only has jurisdiction to regulate tolls and tariffs and that this power does not include the power to regulate its level of revenues or its return on equity.

37 The fixing of tolls and tariffs that are just and reasonable necessarily involves the regulation of the revenues of the regulated entity. This has been recognized by this Court interpreting provisions similar to s. 340(1) of the *Railway Act* which prescribe that "[a]ll tolls shall be just and reasonable". In *B.C. Electric Railway Co. v. Public Utilities Comm. of B.C.*, [1960] S.C.R. 837, 33 W.W.R. 97, 82 C.R.T.C. 32, 25 D.L.R. (2d) 689 , Locke J. said the following about para. 16(1)(b) of the *Public Utilities Act* , R.S.B.C. 1948, c. 277, which provided that in fixing a rate the Public Utility Commission of British Columbia should take into consideration the "fair and reasonable return upon the appraised value of the property of the public utility used ... to enable the public utility to furnish the service", 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, to maintain its properties in a satisfactory state to render adequate service and to provide extensions to these services when, in the opinion of the Commission, such are necessary. In coming to its conclusion as to what constituted a fair return to be allowed to the appellant *these matters as well as the undoubted fact that the earnings must be sufficient, if the company was to discharge these statutory duties, to enable it to pay reasonable dividends and attract capital, either by the sale of shares or securities, were of necessity considered* . Once that decision was made it was, in my opinion, the duty of the Commission imposed by the statute to approve rates which would enable the company to earn such a return or such lesser return as it might decide to ask.

(Emphasis added.) In *Northwestern Utilities Ltd. v. Edmonton*, [1929] S.C.R. 186, [1929] 2 D.L.R. 4 , Lamont J. described the relevant factors in the determination of what are just and reasonable rates as follows, at p. 190 (S.C.R.):

> In order to fix just and reasonable rates, which it was the duty of the Board to fix, the Board had to consider certain elements which must always be taken into account in fixing a rate which is fair and reasonable to the consumer and to the company. One of these is the rate base, by which is meant the amount which the Board considers the owner of the utility has invested in the enterprise and on which he is entitled to a fair return. Another is the percentage to be allowed as a fair return.

Such provisions require the administrative tribunal to balance the interests of the customers with the necessity of ensuring that the regulated entity is allowed to make sufficient revenues to finance the costs of the services it sells to the public.

38 Thus, it is trite to say that in fixing fair and reasonable tolls the appellant must take into consideration the level of revenues needed by the respondent. In fact, the respondent would be the first to complain if its financial situation was not taken into consideration when tolls are fixed. By so doing, the appellant regulates the respondent's revenues, albeit in a seemingly indirect manner. I would therefore dismiss this argument.

c) The power to revisit the period during which interim rates were in force

i) Introduction

39 As indicated above, the appellant has examined the period during which interim rates were in force, i.e. from January 1, 1985 to October 14, 1986, for the purpose of ascertaining whether these interim rates were in fact just and reasonable. Following a factual finding that these rates were not just and reasonable, the one-time credit order now contested before this Court was made in order to remedy this situation. Thus, the effect of Decision 86-17 was not retroactive in nature since it does not seek to establish rates to replace or be substituted to those which were charged during that period. The one-time credit order is, however, retrospective in the sense that its purpose is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive. Thus, the question before this Court is whether the appellant has jurisdiction to make orders for the purpose of remedying the inappropriateness of rates which were approved by it in a previous interim decision.

40 This question involves a determination of whether rates approved by interim order are inherently contingent as well as provisional, or whether the statutory scheme established by the *Railway Act* and the *National Transportation Act* is so prospective in nature that it precluded such a retrospective review of interim rates approved by the appellant. Finally, it is also

necessary to determine whether the appellant has jurisdiction to order the reimbursement of amounts which exceed the revenues actually collected as a direct result of the interim rates.

ii) The distinction between interim and final orders

41 The respondent argues that the *Railway Act* and the *National Transportation Act* establish a regulatory regime which is exclusively prospective in nature because all rates, whether interim or final, must be just and reasonable. Thus, if interim rates have been approved on the basis that they are just and reasonable, no excessive revenues can be earned by charging such rates; interim rates, by reason only of their approval by the appellant, are presumed to be just and reasonable until they are modified by a subsequent order. According to the respondent, interim orders are therefore orders made "for the time being" until a more permanent order is made.

42 In his dissenting reasons, Hugessen J. points out quite accurately that if interim orders are simply orders made "for the time being", it will be impossible to distinguish final orders from interim orders within the statutory scheme established by the *Railway Act* and the *National Transportation Act* since all final orders may be revised by the appellant of its own motion and at any time: s. 335(1) of the *Railway Act* and s. 52 of the *National Transportation Act* . It is therefore impossible to say that final orders made under these statutes are final in the sense that they may never be reconsidered. The on-going nature of the appellant's regulatory activities necessarily entails a continuous review of past decisions concerning tolls and tariffs. Thus, all orders, whether final or interim, would be orders "for the time being" within the statutory scheme established by the *Railway Act* and the *National Transportation Act* .

43 Both the appellant and Hugessen J. rely heavily on *Coseka Resources Ltd. v. Saratoga Processing Co.; Petrogas Processing Ltd. v. Pub. Utilities Bd.* (1981), 16 Alta. L.R. (2d) 60, 126 D.L.R. (3d) 705, 31 A.R. 541 (C.A.) ("*Coseka* ") for the proposition that interim decisions must be distinguished from final decisions in that they may be reviewed in a retrospective manner. This distinction is based on the fact that interim decisions are made subject to "further direction" as prescribed by s. 60(2) of the *National Transportation Act* which, for convenience, I cite again:

> 60. ...
>
> (2) The Commission may, instead of making an order final in the first instance, make an interim order and *reserve further directions* either for an adjourned hearing of the matter or for further application.

(Emphasis added.) The statutory scheme analysed by the Alberta Court of Appeal in *Coseka* , supra, is substantially similar to though more clearly prospective than the statutory scheme established by the *Railway Act* and the *National Transportation Act* . Furthermore, s. 52(2) of the *Public Utilities Board Act* , R.S.A. 1970, c. 302, is identical in wording to s. 60(2) of the *National Transportation Act* . Laycraft J.A., as he then was, cited with approval by Hugessen J., wrote the following with respect to the possibility of revisiting the period during which interim rates were in force for the purpose of deciding whether those interim rates were in fact just and reasonable, at pp. 717-718 (D.L.R.):

> In my view, to say that an interim order may not be replaced by a final order is to attribute virtually no additional powers to the Board from s. 52 beyond those already contained in either the *Gas Utilities Act* or the *Public Utilities Board Act* to make final orders. The Board is by other provisions of the statute empowered by order to fix rates either on application or on its own motion. *An interim order would be the same, and have the same effect, as a final order unless the 'further direction' which the statute contemplates includes the power to change the interim order. On that construction of the section the interim order would be a 'final' order in all but name* . The Board would need no further legislative authority to issue a further 'final' order since it may fix rates under s. 27 on its own motion without a further application. The provision for an interim order was intended to permit rates to be fixed subject to correction to be made when the hearing is subsequently completed.
>
> It was urged during argument that s. 52(2) was merely intended to enable the Board to achieve 'rough justice' during the period of its operation until a final order is issued. However, the Board is required to fix 'just and reasonable rates' not

> 'roughly just and reasonable rates'. The words 'reserve for further direction', in my view, contemplate changes as soon as the Board is able to determine those just and reasonable rates.

(Emphasis added.)

44 I agree with Hugessen J. and with the reasons of Laycraft J.A. in *Coseka* where he made a careful review of previous cases. The statutory scheme established by the *Railway Act* and the *National Transportation Act* is such that one of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect, as well as any discrepancy between the interim order and the final order, may be reviewed and remedied by the final order. I hasten to add that the words "further directions" do not have any magical, retrospective content. Under the *Railway Act* and the *National Transportation Act* , final orders are subject to "further [prospective] directions" as well. It is the interim nature of the order which makes it subject to further retrospective directions.

45 The importance of distinguishing final orders from interim orders is illustrated by the case of *City of Calgary v. Madison Natural Gas Co.* (1959), 19 D.L.R. (2d) 655 (Alta. C.A.) ("*Madison* "). In *Madison* , supra, the Public Utility Board (the "Board") was faced with an application by the City of Calgary for the reimbursement of amounts earned in excess of the rates of the rates of return allowed in orders 34 and 41 for the sale of natural gas. The Board had allowed a rate of return of 7 per cent but, due to its lack of useful information to predict the effect of rates on the actual financial performance of the regulated entity, the rates per volume fixed by the Board actually yielded greater profits than anticipated. The Board refused to grant the demands made in the application because it felt it had no jurisdiction to revisit periods during which rates approved in a final decision were in force. This decision was confirmed by the Court of Appeal on the basis that, contrary to arguments made by the City of Calgary, orders 34 and 41 were final orders not governed by s. 35*a* (3) of the *Natural Gas Utilities Act* , S.A. 1944, c. 4, which read as follows:

> 35a ...
>
> (3) The Board is hereby authorized, empowered and directed, on the final hearing, to give consideration to the effect of the operation of such interim or temporary order and in the final order to make, allow or provide for such adjustments, allowances or other factors, as to the Board may seem just and reasonable.

Order 34 provided that the price was set at 9 cents per mcf and that "if it should turn out that there is a surplus, it can be dealt with when the time arrives" which led to the argument that this order was in fact an interim order. Johnson J.A. dismissed this argument in the following terms, at pp. 662-663:

> It is the submission of the appellants that O. 34 and O. 41 are interim or temporary orders and the Board can now deal with these surpluses in accordance with s-s (3). As I have mentioned, orders fixing interim prices were made while the Board was hearing the application and considering its report. These, of course, were superseded by the order now under consideration. Orders 34 and 41 are, of course, not final orders in the sense that judgments are final. The Act contemplates that subsequent applications will be made to change the price fixed by these orders. They are nonetheless final so far as each application is concerned.

It is useful to note that the respondent relies heavily on the *Madison* case for the proposition that a regulated entity cannot be forced to disgorge profits legally earned by charging rates approved by the relevant regulatory authority on the basis that they are just and reasonable. Since the City of Calgary sought to obtain the reimbursement of profits earned by charging rates approved by final order, this case does not support the respondent's position.

46 A consideration of the nature of interim orders and the circumstances under which they are granted further explains and justifies their being, unlike final decisions, subject to retrospective review and remedial orders. The appellant may make a wide variety of interim orders dealing with hearings, notices and, in general, all matters concerning the administration of proceedings before the appellant. Such orders are obviously interim in nature. However, this is less obvious when an interim order deals with a matter which is to be dealt with in the final decision, as was the case with the interim rate increase ordered in Decision 84-28. If interim rate increases are awarded on the basis of the same criteria as those applied in the final decision, the interim

decision would serve as a preliminary decision on the merits as far as the rate increase is concerned. This, however, is not the purpose of interim rate orders.

47 Traditionally, such interim rate orders dealing in an interlocutory manner with issues which remain to be decided in a final decision are granted for the purpose of relieving the applicant from the deleterious effects caused by the length of the proceedings. Such decisions are made in an expeditious manner on the basis of evidence which would often be insufficient for the purposes of the final decision. The fact that an order does not make any decision on the merits of an issue to be settled in a final decision, and the fact that its purpose is to provide temporary relief against the deleterious effects of the duration of the proceedings, are essential characteristics of an interim rate order.

48 In Decision 84-28, the appellant granted the respondent an interim rate increase on the basis of the following criteria which, for convenience, I cite again, at p. 9:

> The Commission considers that, as a rule, general rate increases should only be granted following the full public process contemplated by Part III of its Telecommunications Rules of Procedure. In the absence of such a process, general rate increases should not in the Commission's view be granted, even on an interim basis, except where special circumstances can be demonstrated. Such circumstances would include lengthy delays in dealing with an application that could result in a serious deterioration in the financial condition of an applicant absent a general interim increase.

Decision 84-28 was truly an interim decision since it did not seek to decide in a preliminary manner an issue which would be dealt with in the final decision. Instead, the appellant granted the interim rate increase on the basis that such an increase was necessary in order to prevent the respondent from having serious financial difficulties.

49 Furthermore, the appellant consistently reiterated throughout the procedures which led to Decision 86-17 its intention to review the rates charged for the test year 1985 and up to the date of the final decision. Holding that the interim rates in force during that period cannot be reviewed would not only be contrary to the nature of interim orders, it would also frustrate and subvert the appellant's order approving interim rates.

50 It is true, as the respondent argues, that all telephone rates approved by the appellant must be just and reasonable whether these rates are approved by interim or final order; no other conclusion can be derived from s. 340(1) of the *Railway Act* . However, interim rates must be just and reasonable on the basis of the evidence filed by the applicant at the hearing or otherwise available for the interim decision. It would be useless to order a final hearing if the appellant was bound by the evidence filed at the interim hearing. Furthermore, the interim rate increase was granted on the basis that the length of the proceedings could cause a serious deterioration in the financial condition of the respondent. Only once such an emergency situation was found to exist did the appellant ask itself what rate increase would be just and reasonable on the basis of the available evidence and for the purpose of preventing such a financial deterioration. The inherent differences between a decision made on an interim basis and a decision made on a final basis clearly justify the power to revisit the period during which interim rates were in force.

51 The respondent argues that the power to revisit the period during which interim rates were in force cannot exist within the statutory scheme established by the *Railway Act* and the *National Transportation Act* because these statutes do not grant such a power explicitly, unlike s. 64 of the *National Energy Board Act* , R.S.C. 1985, c. N-7. The powers of any administrative tribunal must of course be stated in its enabling statute, but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although Courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes. I have found that, within the statutory scheme established by the *Railway Act* and the *National Transportation Act* , the power to make interim orders necessarily implies the power to revisit the period during which interim rates were in force. The fact that this power is provided explicitly in other statutes cannot modify this conclusion based as it is on the interpretation of these two statutes as a whole.

52 I am bolstered in my opinion by the fact that the regulatory scheme established by the *Railway Act* and the *National Transportation Act* gives the appellant very broad procedural powers for the purpose of ensuring that telephone rates and tariffs

are, at all times, just and reasonable. Within this regulatory framework, the power to make appropriate orders for the purpose of remedying interim rates which are not just and reasonable is a necessary adjunct to the power to make interim orders.

53 It is interesting to note that, in the context of statutory schemes which did not provide any power to set interim rates, the United States Supreme Court has held that regulatory agencies have both the power to impose interim rates and the power to make reimbursement orders where the interim rates are found to be excessive in the final order: see *U.S. v. Fulton* (1986), 475 U.S. 657 , at pp. 669-671; *Re Trans Alaska Pipeline Rate Cases* (1978), 436 U.S. 631, where Brennan J. wrote the following comments, at pp. 654-656:

> Finally, petitioners contend that the Commission has no power to subject them to an obligation to account for and refund amounts collected under the interim rates in effect during the suspension period and the initial rates which would become effective at the end of such a period ... In response, we note first that we have already recognized in *Chessie* that the Commission does have powers 'ancillary' to its suspension power which do not depend on an express statutory grant of authority. We had no occasion in *Chessie* to consider what the full range of such powers might be, but we did indicate that the touchstone of ancillary power was a 'direc(t) relat(ionship)' between the power asserted and the Commission's 'mandate to assess the reasonableness of ... rates and to suspend them pending investigation if there is a question as to their legality.' 426 U.S., at 514.
>
> Thus, here as in *Chessie* , the Commission's refund conditions are a 'legitimate, reasonable, and direct adjunct to the Commission's explicit statutory power to suspend rates pending investigation,' in that they allow the Commission, in exercising its suspension power, to pursue 'a more measured course' and to 'offe[r] an alternative tailored far more precisely to the particular circumstances' of these cases. Since, again as in *Chessie* , the measured course adopted here is necessary to strike a proper balance between the interests of carriers and the public, we think the *Interstate Commerce Act* should be construed to confer on the Commission the authority to enter on this course unless language in the Act plainly requires a contrary result.

This approach to the interpretation of statutes conferring regulatory authority over rates and tariffs is only the expression of the wider rule that the Court must not stifle the legislator's intention by reason only of the fact that a power has not been explicitly provided for.

54 The appellant has also argued that the power to "vary" a previous decision, whether interim or final, found in s. 66 of the *National Transportation Act* , includes the power to vary these decisions in a retroactive manner. Given my conclusion based on the inherent nature of interim orders, it is unnecessary for me to deal with this argument.

iii) The relevance of the distinction between positive approval and negative disallowance schemes of rate regulation

55 Much was said in argument about the difference between positive approval schemes and negative disallowance schemes, with respect to the power to act retrospectively. The first category includes schemes which provide that the administrative agency is the only body having statutory authority to approve or fix tolls payable to utility companies; these schemes generally stipulate that tolls shall be "just and reasonable" and that the administrative agency has the power to review these tolls on a proprio motu basis, or upon application by an interested party. The second category includes schemes which grant utility companies the right to fix tolls as they wish, but also grant users the right to complain before an administrative agency which has the power to vary those tolls if it finds that they are not "just and reasonable". It has generally been found that negative disallowance schemes provide the power to make orders which are retroactive to the date of the application, by the ratepayer who claims that the rates are not "just and reasonable". On the other hand, positive approval schemes have been found to be exclusively prospective in nature and not to allow orders applicable to periods prior to the final decision itself. A full discussion of this issue was made by Estey J. in *Nova v. Amoco Can. Petroleum Co.*, [1981] 2 S.C.R. 437 at 450-451, [1981] 6 W.W.R. 391, 38 N.R. 381, 128 D.L.R. (3d) 1, 32 A.R. 384 , and I do not propose to repeat or to criticize what was said in that case with respect to the power to review rates approved by a previous final order. I am of the opinion that the regulatory scheme established by the *Railway Act* and the *National Transportation Act* is a positive approval scheme inasmuch as the respondent's rates are subject to approval

by the appellant. However, the *Nova* case, supra, only dealt with the power to review rates approved in a previous final decision and, as I have said before, entirely different considerations apply when interim rates are reviewed.

56 It has often been said that the power to review its own previous final decision on the fairness and the reasonableness of rates would threaten the stability of the regulated entity's financial situation. In *R. v. Bd. of Commrs. of Public Utilities (N.B.); Ex parte Moncton Utility Gas Ltd.* (1966), 60 D.L.R. (2d) 703 , Ritchie J.A., as he then was, wrote the following comments on this issue, at p. 729:

> The distributor contends that in the absence of any express limitation or restriction or an express provision as to the effective date of any order made by the board, the jurisdiction conferred on the board by the Legislature includes jurisdiction to make orders with retrospective effect. Reliance is placed on *Bakery and Confectionery Workers International Union of America, Local 468 v. Salmi, White Lunch Ltd. v. Labour Relations Board of British Columbia*, 56 D.L.R. (2d) 193, [1966] S.C.R. 282, 55 W.W.R. 129 which it is contended must be applied when interpreting s. 6(1) of the Act.
>
> The clear object of the Act is to ensure stability in the operation of public utilities and the maintenance of just, reasonable and non-discriminatory rates. That object would be defeated if the board having, on November 14, 1962, made an order fixing the rates to be paid by the distributor for natural gas purchased from the producer, reduced those rates on February 19, 1966, more than three years later, and directed that the reduced rates be effective as from January 1, 1962, or as from any other date prior to February 19, 1966.

and further at p. 732:

> In no section of the Act do I find any wording indicating an intention on the part of the Legislature to confer on the board authority to make orders fixing rates with retrospective effect or any language requiring a construction that such authority has been bestowed on the board. To so interpret s. 6(1) would render insecure the position of not only every public utility carrying on business in the Province but also the position of every customer of such public utility.

However, Ritchie J.A.'s comments deal with the *Public Utilities Act* , R.S.N.B. 1952, c. 186, which did not provide the Board with any power to make interim orders. I readily agree that Ritchie J.A.'s concerns about the financial stability of utility companies are valid when one is faced with the argument that a Board has the power to revisit its own previous final decisions. Since no time limit could be placed on the period which could be revisited, any power to revisit previous final decisions would have to be explicitly provided in the enabling statute. Furthermore, even if final orders are "for the time being", it does not necessarily follow that they must be stripped of all their finality through the judicial recognition of a power to revisit a period during which final rates were in force.

57 However, there should be no concern over the financial stability of regulated utility companies where one deals with the power to revisit interim rates. The very purpose of interim rates is to allay the prospect of financial instability which can be caused by the duration of proceedings before a regulatory tribunal. In fact, in this case, the respondent asked for and was granted interim rate increases on the basis of serious apprehended financial difficulties. The added flexibility provided by the power to make interim orders is meant to foster financial stability throughout the regulatory process. The power to revisit the period during which interim rates were in force is a necessary corollary of this power, without which interim orders made in emergency situations may cause irreparable harm and subvert the fundamental purpose of ensuring that rates are just and reasonable.

58 Even though Parliament has decided to adopt a positive approval regulatory scheme for the regulation of telephone rates, the added flexibility provided by the power to make interim orders indicates that the appellant is empowered to make orders as of the date at which the initial application was made or as of the date the appellant initiated the proceedings of its own motion. The underlying theory behind the rule that a positive approval scheme only gives jurisdiction to make prospective orders is that the rates are presumed to be just and reasonable until they are modified because they have been approved by the regulatory authority on the basis that they were indeed just and reasonable. However, the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order. As a result, it cannot be said that the rate review process begins at the date of the final hearing; instead, the rate review begins when the appellant sets interim

rates pending a final decision on the merits. As was stated in obiter in *Re Eurocan Pulp & Paper Co. and B.C. Energy Commn.* (1978), 87 D.L.R. (3d) 727 (B.C.C.A.) , with respect to a similar though not identical legislative scheme, the power to make interim orders effectively implies the power to make orders effective from the date of the beginning of the proceedings. In turn, this power must comprise the power to make appropriate orders for the purpose of remedying any discrepancy between the rate of return yielded by the interim rates and the rate of return allowed in the final decision for the period during which they are in effect, so as to achieve just and reasonable rates throughout that period.

iv) The power to make a one-time credit order

59 Once it is decided, as I have, that the appellant does have the power to revisit the period during which interim rates were in force for the purpose of ascertaining whether they were just and reasonable, it would be absurd to hold that it has no power to make a remedial order where, in fact, these rates were not just and reasonable. I also agree with Hugessen J. that s. 340(5) of the *Railway Act* provides a sufficient statutory basis for the power to make remedial orders, including an order to give a one-time credit to certain classes of customers.

60 C.N.C.P. Telecommunications argues that the one-time credit order should be limited to the amount of revenues actually derived as a direct result of the 2 per cent interim rate increase and that these excess revenues should be refunded to the actual customers who paid them. The presumption behind this argument is that the portion of the interim rates corresponding to the final rates in force prior to the beginning of the proceedings cannot be held to be unjust or unreasonable until a final decision is rendered. As I have held that the appellant has jurisdiction to review the fairness and the reasonableness of these interim rates in their entirety because the rate-review process starts as of the date of the beginning of the proceedings, this argument must be dismissed.

61 Finally, it is true that the one-time credit ordered by the appellant will not necessarily benefit the customers who were actually billed excessive rates. However, once it is found that the appellant does have the power to make a remedial order, the nature and extent of this order remain within its jurisdiction in the absence of any specific statutory provision on this issue. The appellant admits that the use of a one-time credit is not the perfect way of reimbursing excess revenues. However, in view of the cost and the complexity of finding who actually paid excessive rates, where these persons reside, and of quantifying the amount of excessive payments made by each, and having regard to the appellant's broad jurisdiction in weighing the many factors involved in apportioning respondent's revenue requirement amongst its several classes of customers to determine just and reasonable rates, the appellant's decision was eminently reasonable and I agree with Hugessen J. that it should not be overturned.

VI — Conclusion

62 In my opinion, the appellant had jurisdiction to review the interim rates in force prior to Decision 86-17 for the purpose of ascertaining whether they were just and reasonable, had jurisdiction to order the respondent to grant the one-time credit described in Decision 86-17, and has committed no error in so doing.

63 I would allow the appeal and confirm the appellant's decision, with costs in all Courts.

Appeal allowed. Decision of Canadian Radio-Television Telecommunications Commission affirmed.

2006 SCC 4
Supreme Court of Canada

ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)

2006 CarswellAlta 139, 2006 CarswellAlta 140, 2006 SCC 4, [2006] 1 S.C.R. 140, [2006] 5 W.W.R. 1, [2006] A.W.L.D. 775, [2006] A.C.S. No. 4, [2006] S.C.J. No. 4, 263 D.L.R. (4th) 193, 344 N.R. 293, 363 W.A.C. 1, 380 A.R. 1, 39 Admin. L.R. (4th) 159, 54 Alta. L.R. (4th) 1, J.E. 2006-358

City of Calgary (Appellant/Respondent on cross-appeal) v. ATCO Gas and Pipelines Ltd. (Respondent/Appellant on cross-appeal) and Alberta Energy and Utilities Board, Ontario Energy Board, Enbridge Gas Distribution Inc. and Union Gas Limited (Interveners)

McLachlin C.J.C., Bastarache, Binnie, LeBel, Deschamps, Fish, Charron JJ.

Heard: May 11, 2005

Judgment: February 9, 2006 *

Docket: 30247

Proceedings: reversing in part *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)* (2004), 24 Alta. L.R. (4th) 205, [2004] 4 W.W.R. 239, 312 W.A.C. 250, 339 A.R. 250, 2004 CarswellAlta 55, 2004 ABCA 3 (Alta. C.A.)

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George Vegh, Michael W. Lyle (written submissions), for intervener, Ontario Energy Board
Michael D. Schafler, J.L. McDougall, Q.C. (written submissions), for Intervener, Enbridge Gas Distribution Inc.
Michael A. Penny, Susan Kushneryk (written submissions), for Intervener, Union Gas Limited

***Bastarache J.*:**

1. Introduction

1 At the heart of this appeal is the issue of the jurisdiction of an administrative board. More specifically, the Court must consider whether, on the appropriate standard of review, this utility board appropriately set out the limits of its powers and discretion.

2 Few areas of our lives are now untouched by regulation. Telephone, rail, airline, trucking, foreign investment, insurance, capital markets, broadcasting licences and content, banking, food, drug and safety standards, are just a few of the objects of public regulations in Canada: M. J. Trebilcock, "The Consumer Interest and Regulatory Reform", in G. B. Doern, ed., *The Regulatory Process in Canada* (1978), 94. Discretion is central to the regulatory agency policy process, but this discretion will vary from one administrative body to another (see C. L. Brown-John, *Canadian Regulatory Agencies: Quis custodiet ipsos custodes*? (1981), at p. 29). More importantly, in exercising this discretion, statutory bodies must respect the confines of their jurisdiction: they cannot trespass in areas where the legislature has not assigned them authority (see D. J. Mullan, *Administrative Law* (2001), at pp. 9-10).

3 The business of energy and utilities is no exception to this regulatory framework. The respondent in this case is a public utility in Alberta which delivers natural gas. This public utility is nothing more than a private corporation subject to certain regulatory constraints. Fundamentally, it is like any other privately held company: it obtains the necessary funding from investors through

public issues of shares in stock and bond markets; it is the sole owner of the resources, land and other assets; it constructs plants, purchases equipment, and contracts with employees to provide the services; it realizes profits resulting from the application of the rates approved by the Alberta Energy and Utilities Board (the "Board") (see P. W. MacAvoy and J. G. Sidak, "The Efficient Allocation of Proceeds from a Utility's Sale of Assets" (2001), 22 *Energy L.J.* 233, at p. 234). That said, one cannot ignore the important feature which makes a public utility so distinct: it must answer to a regulator. Public utilities are typically natural monopolies: technology and demand are such that fixed costs are lower for a single firm to supply the market than would be the case where there is duplication of services by different companies in a competitive environment (see A. E. Kahn, *The Economics of Regulation: Principles and Institutions* (1988), vol. 1, at p. 11; B. W. F. Depoorter, "Regulation of Natural Monopoly", in B. Bouckaert and G. De Geest, eds., *Encyclopedia of Law and Economics* (2000), vol. III, 498; J. S. Netz, "Price Regulation: A (Non-Technical) Overview", in B. Bouckaert and G. De Geest, eds., *Encyclopedia of Law and Economics* (2000), vol. III, 396, at p. 398; A. J. Black, "Responsible Regulation: Incentive Rates for Natural Gas Pipelines" (1992), 28 *Tulsa L.J.* 349, at p. 351). Efficiency of production is promoted under this model. However, governments have purported to move away from this theoretical concept and have adopted what can only be described as a "regulated monopoly". The utility regulations exist to protect the public from monopolistic behaviour and the consequent inelasticity of demand while ensuring the continued quality of an essential service (see Kahn, at p. 11).

4 As in any business venture, public utilities make business decisions, their ultimate goal being to maximize the residual benefits to shareholders. However, the regulator limits the utility's managerial discretion over key decisions, including prices, service offerings and the prudency of plant and equipment investment decisions. And more relevant to this case, the utility, outside the ordinary course of business, is limited in its right to sell assets it owns: it must obtain authorization from its regulator before selling an asset previously used to produce regulated services (see MacAvoy and Sidak, at p. 234).

5 Against this backdrop, the Court is being asked to determine whether the Board has jurisdiction pursuant to its enabling statutes to allocate a portion of the net gain on the sale of a now discarded utility asset to the rate-paying customers of the utility when approving the sale. Subsequently, if this first question is answered affirmatively, the Court must consider whether the Board's exercise of its jurisdiction was reasonable and within the limits of its jurisdiction: was it allowed, in the circumstances of this case, to allocate a portion of the net gain on the sale of the utility to the rate-paying customers?

6 The customers' interests are represented in this case by the City of Calgary (the "City") which argues that the Board can determine how to allocate the proceeds pursuant to its power to approve the sale and protect the public interest. I find this position unconvincing.

7 The interpretation of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 ("AEUBA"), the *Public Utilities Board Act*, R.S.A. 2000, c. P-45 ("PUBA"), and the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("GUA") (see Appendix for the relevant provisions of these three statutes), can lead to only one conclusion: the Board does not have the prerogative to decide on the distribution of the net gain from the sale of assets of a utility. The Board's seemingly broad powers to make any order and to impose any additional conditions that are necessary in the public interest has to be interpreted within the entire context of the statutes which are meant to balance the need to protect consumers as well as the property rights retained by owners, as recognized in a free market economy. The limits of the powers of the Board are grounded in its main function of fixing just and reasonable rates ("rate setting") and in protecting the integrity and dependability of the supply system.

1.1 Overview of the Facts

8 ATCO Gas - South ("AGS"), which is a division of ATCO Gas and Pipelines Ltd. ("ATCO"), filed an application by letter with the Board pursuant to s. 25.1(2) (now s. 26(2)) of the GUA, for approval of the sale of its properties located in Calgary known as Calgary Stores Block (the "property"). The property consisted of land and buildings; however, the main value was in the land, and the purchaser intended to and did eventually demolish the buildings and redevelop the land. According to AGS, the property was no longer used or useful for the provision of utility services, and the sale would not cause any harm to customers. In fact, AGS suggested that the sale would result in cost savings to customers, by allowing the net book value of the property to be retired and withdrawn from the rate base, thereby reducing rates. ATCO requested that the Board approve the sale transaction and the disposition of the sale proceeds to retire the remaining book value of the sold assets, to recover the disposition costs,

and to recognize the balance of the profits resulting from the sale of the plant should be paid to shareholders. The Board dealt with the application in writing, without witnesses or an oral hearing. Other parties making written submissions to the Board were the City of Calgary, the Federation of Alberta Gas Co-ops Ltd., Gas Alberta Inc. and the Municipal Interveners, who all opposed ATCO's position with respect to the disposition of the sale proceeds to shareholders.

1.2 Judicial History

1.2.1 Alberta Energy and Utilities Board

1.2.1.1 Decision 2001-78 (Atco Gas and Pipelines Ltd.)

9 In a first decision, which considered ATCO's application to approve the sale of the property, the Board employed a "no-harm" test, assessing the potential impact on both rates and the level of service to customers and the prudence of the sale transaction, taking into account the purchaser and tender or sale process followed. The Board was of the view that the test had been satisfied. It was persuaded that customers would not be harmed by the sale, given that a prudent lease arrangement to replace the sold facility had been concluded. The Board was satisfied that there would not be a negative impact on customers' rates, at least during the five-year initial term of the lease. In fact, the Board concluded that there would be cost savings to the customers and that there would be no impact on the level of service to customers as a result of the sale. It did not make a finding on the specific impact on future operating costs; for example, it did not consider the costs of the lease arrangement entered into by ATCO. The Board noted that those costs could be reviewed by the Board in a future general rate application brought by interested parties.

1.2.1.2 Decision 2002-037, (Alta. E.U.B.)

10 In a second decision, the Board determined the allocation of net sale proceeds. It reviewed the regulatory policy and general principles which affected the decision, although no specific matters are enumerated for consideration in the applicable legislative provisions. The Board had previously developed a "no-harm" test, and it reviewed the rationale for the test as summarized in its Alta. E.U.B. Decision 2001-65, *Atco Gas-North, A Division of Atco Gas and Pipelines Ltd.*: "The Board considers that its power to mitigate or offset potential harm to customers by allocating part or all of the sale proceeds to them, flows from its very broad mandate to protect consumers in the public interest (p. 16)."

11 The Board went on to discuss the implications of the Alberta Court of Appeal decision in *Transalta Utilities Corp. v. Alberta (Public Utilities Board)* (1986), 68 A.R. 171 (Alta. C.A.), referring to various decisions it had rendered in the past. Quoting from Alta. E.U.B. Decision 2000-41 (*TransAlta Utilities Corp.*), the Board summarized the "*TransAlta Formula*" (para. 27):

> In subsequent decisions, the Board has interpreted the Court of Appeal's conclusion to mean that where the sale price exceeds the original cost of the assets, shareholders are entitled to net book value (in historical dollars), customers are entitled to the difference between net book value and original cost, and any appreciation in the value of the assets (i.e. the difference between original cost and the sale price) is to be shared by shareholders and customers. The amount to be shared by each is determined by multiplying the ratio of sale price/original cost to the net book value (for shareholders) and the difference between original cost and net book value (for customers). However, where the sale price does not exceed original cost, customers are entitled to all of the gain on sale.

The Board also referred to Decision 2001-65, where it had clarified the following (para. 28):

> In the Board's view, if the TransAlta Formula yields a result greater than the no-harm amount, customers are entitled to the greater amount. If the TransAlta Formula yields a result less than the no-harm amount, customers are entitled to the no-harm amount. In the Board's view, this approach is consistent with its historical application of the TransAlta Formula.

12 On the issue of its jurisdiction to allocate the net proceeds of a sale, the Board in the present case stated, at paras. 47-49:

> The fact that a regulated utility must seek Board approval before disposing of its assets is sufficient indication of the limitations placed by the legislature on the property rights of a utility. In appropriate circumstances, the Board clearly has

> the power to prevent a utility from disposing of its property. In the Board's view it also follows that the Board can approve a disposition subject to appropriate conditions to protect customer interests.
>
> Regarding AGS's argument that allocating more than the no-harm amount to customers would amount to retrospective ratemaking, the Board again notes the decision in the TransAlta Appeal. The Court of Appeal accepted that the Board could include in the definition of "revenue" an amount payable to customers representing excess depreciation paid by them through past rates. In the Board's view, no question of retrospective ratemaking arises in cases where previously regulated rate base assets are being disposed of out of rate base and the Board applies the TransAlta Formula.
>
> The Board is not persuaded by the Company's argument that the Stores Block assets are now 'non-utility' by virtue of being 'no longer required for utility service'. The Board notes that the assets could still be providing service to regulated customers. In fact, the services formerly provided by the Stores Block assets continue to be required, but will be provided from existing and newly leased facilities. Furthermore, the Board notes that even when an asset and the associated service it was providing to customers is no longer required the Board has previously allocated more than the no-harm amount to customers where proceeds have exceeded the original cost of the asset.

13 The Board went on to apply the no-harm test to the present facts. It noted that in its decision on the application for the approval of the sale, it had already considered the no-harm test to be satisfied. However, in that first decision, it had not made a finding with respect to the specific impact on future operating costs, including the particular lease arrangement being entered into by ATCO.

14 The Board then reviewed the submissions with respect to the allocation of the net gain and rejected the submission that if the new owner had no use of the buildings on the land, this should affect the allocation of net proceeds. The Board held that the buildings did have some present value but did not find it necessary to fix a specific value. The Board recognized and confirmed that the *TransAlta Formula* was one whereby the "windfall" realized when the proceeds of sale exceed the original cost could be shared between customers and shareholders. It held that it should apply the formula in this case and that it would consider the gain on the transaction as a whole, not distinguishing between the proceeds allocated to land separately from the proceeds allocated to buildings.

15 With respect to allocation of the gain between customers and shareholders of ATCO, the Board tried to balance the interests of both the customers' desire for safe reliable service at a reasonable cost with the provision of a fair return on the investment made by the company (paras. 112-13):

> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.
>
> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred.

16 The Board went on to conclude that the sharing of the net gain on the sale of the land and buildings collectively, in accordance with the *TransAlta Formula*, was equitable in the circumstances of this application and was consistent with past Board decisions.

17 The Board determined that from the gross proceeds of $6,550,000, ATCO should receive $465,000 to cover the cost of disposition ($265,000) and the provision for environmental remediation ($200,000), the shareholders should receive $2,014,690, and $4,070,310 should go to the customers. Of the amount credited to shareholders, $225,245 was to be used to remove the remaining net book value of the property from ATCO's accounts. Of the amount allocated to customers, $3,045,813 was allocated to ATCO Gas - South customers and $1,024,497 to ATCO Pipelines - South customers.

1.2.2 Court of Appeal of Alberta (24 Alta. L.R. (4th) 205, 2004 ABCA 3 (Alta. C.A.))

18 ATCO appealed the Board's decision. It argued that the Board did not have any jurisdiction to allocate the proceeds of sale and that the proceeds should have been allocated entirely to the shareholders. In its view, allowing customers to share in the proceeds of sale would result in them benefiting twice, since they had been spared the costs of renovating the sold assets and would enjoy cost savings from the lease arrangements. The Court of Appeal of Alberta agreed with ATCO, allowing the appeal and setting aside the Board's decision. The matter was referred back to the Board, and the Board was directed to allocate the entire amount appearing in Line 11 of the allocation of proceeds, entitled "Remainder to be Shared" to ATCO. For the reasons that follow, the Court of Appeal's decision should be upheld, in part; it did not err when it held that the Board did not have the jurisdiction to allocate the proceeds of the sale to ratepayers.

2. Analysis

2.1 Issues

19 There is an appeal and a cross-appeal in this case: an appeal by the City in which it submits that, contrary to the Court of Appeal's decision, the Board had jurisdiction to allocate a portion of the net gain on the sale of a utility asset to the rate-paying customers, even where no harm to the public was found at the time the Board approved the sale, and a cross-appeal by ATCO in which it questions the Board's jurisdiction to allocate any of ATCO's proceeds from the sale to customers. In particular, ATCO contends that the Board has no jurisdiction to make an allocation to rate-paying customers, equivalent to the accumulated depreciation calculated for prior years. No matter how the issue is framed, it is evident that the crux of this appeal lies in whether the Board has the jurisdiction to distribute the gain on the sale of a utility company's asset.

20 Given my conclusion on this issue, it is not necessary for me to consider whether the Board's allocation of the proceeds in this case was reasonable. Nevertheless, as I note at para. 82, I will direct my attention briefly to the question of the exercise of discretion in view of my colleague's reasons.

2.2 Standard of Review

21 As this appeal stems from an administrative body's decision, it is necessary to determine the appropriate level of deference which must be shown to the body. Wittman J.A., writing for the Court of Appeal, concluded that the issue of jurisdiction of the Board attracted a standard of correctness. ATCO concurs with this conclusion. I agree. No deference should be shown for the Board's decision with regard to its jurisdiction on the allocation of the net gain on sale of assets. An inquiry into the factors enunciated by this Court in *Pushpanathan v. Canada (Minister of Employment & Immigration)*, [1998] 1 S.C.R. 982 (S.C.C.), confirms this conclusion, as does the reasoning in *United Taxi Drivers' Fellowship of Southern Alberta v. Calgary (City)*, [2004] 1 S.C.R. 485, 2004 SCC 19 (S.C.C.).

22 Although it is not necessary to conduct a full analysis of the standard of review in this case, I will address the issue briefly in light of the fact that Binnie J. deals with the exercise of discretion in his reasons for judgment. The four factors that need to be canvassed in order to determine the appropriate standard of review of an administrative tribunal decision are: 1) the existence of a privative clause; 2) the expertise of the tribunal/board; 3) the purpose of the governing legislation and the particular provisions; and 4) the nature of the problem (*Pushpanathan*, at paras. 29-38).

23 In the case at bar, one should avoid a hasty characterizing of the issue as "jurisdictional" and subsequently be tempted to skip the pragmatic and functional analysis. A complete examination of the factors is required.

24 First, s. 26(1) of the AEUBA grants a right of appeal, but in a limited way. Appeals are allowed on a question of jurisdiction or law and only after leave to appeal is obtained from a judge:

> 26(1) Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.
>
> (2) Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made

(a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or

(b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

In addition, the AEUBA includes a privative clause which states that every action, order, ruling or decision of the Board is final and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court (s. 27).

25 The presence of a statutory right of appeal on questions of jurisdiction and law suggests a more searching standard of review and less deference to the Board on those questions (see *Pushpanathan*, at para. 30). However, the presence of the privative clause and right to appeal are not decisive, and one must proceed with the examination of the nature of the question to be determined and the relative expertise of the tribunal in those particular matters.

26 Second, as observed by the Court of Appeal, no one disputes the fact that the Board is a specialized body with a high level of expertise regarding Alberta's energy resources and utilities (see, e.g., *Consumers' Gas Co. v. Ontario (Energy Board)*, [2001] O.J. No. 5024 (Ont. Div. Ct.), at para. 2; *Coalition of Citizens Impacted by the Caroline Shell Plant v. Alberta (Energy & Utilities Board)* (1996), 41 Alta. L.R. (3d) 374 (Alta. C.A.), at para. 14. In fact, the Board is a permanent tribunal with a long-term regulatory relationship with the regulated utilities.

27 Nevertheless, the Court is concerned not with the general expertise of the administrative decision maker, but with its expertise in relation to the specific nature of the issue before it. Consequently, while normally one would have assumed that the Board's expertise is far greater than that of a court, the nature of the problem at bar, to adopt the language of the Court of Appeal (para. 35), "neutralizes" this deference. As I will elaborate below, the expertise of the Board is not engaged when deciding the scope of its powers.

28 Third, the present case is governed by three pieces of legislation: the PUBA, the GUA and the AEUBA. These statutes give the Board a mandate to safeguard the public interest in the nature and quality of the service provided to the community by public utilities: *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557 (S.C.C.), at p. 576; *Dome Petroleum Ltd. v. Alberta (Public Utilities Board)* (1976), 2 A.R. 453 (Alta. C.A.), at paras. 20-22, aff'd [1977] 2 S.C.R. 822 (S.C.C.). The legislative framework at hand has as its main purpose the proper regulation of a gas utility in the public interest, more specifically the regulation of a monopoly in the public interest with its primary tool being rate setting, as I will explain later.

29 The particular provision at issue, s. 26(2)(d)(i) of the GUA, which requires a utility to obtain the approval of the regulator before it sells an asset, serves to protect the customers from adverse results brought about by any of the utility's transactions by ensuring that the economic benefits to customers are enhanced (MacAvoy and Sidak, at pp. 234-36).

30 While at first blush the purposes of the relevant statutes and of the Board can be conceived as a delicate balancing between different constituencies, i.e., the utility and the customer, and therefore entail determinations which are polycentric (*Pushpanathan*, at para. 36), the interpretation of the enabling statutes and the particular provisions under review (s. 26(2)(d) GUA and s. 15(3)(d) AEUBA) is not a polycentric question, contrary to the conclusion of the Court of Appeal. It is an inquiry into whether a proper construction of the enabling statutes gives the Board jurisdiction to allocate the profits realized from the sale of an asset. The Board was not created with the main purpose of interpreting the AEUBA, the GUA or the PUBA in the abstract, where no policy consideration is at issue, but rather to ensure that utility rates are always just and reasonable (see *Atco Ltd.*, at p. 576). In the case at bar, this protective role does not come into play. Hence, this factor points to a less deferential standard of review.

31 Fourth, the nature of the problem underlying each issue is different. The parties are in essence asking the Court to answer two questions (as I have set out above), the first of which is to determine whether the power to dispose of the proceeds of sale falls within the Board's statutory mandate. The Board, in its decision, determined that it had the power to allocate a portion of the proceeds of a sale of utility assets to the ratepayers; it based its decision on its statutory powers, the equitable principles

rooted in the "regulatory compact" (see para. 63 of these reasons) and previous practice. This question is undoubtedly one of law and jurisdiction. The Board would arguably have no greater expertise with regard to this issue than the courts. A court is called upon to interpret provisions that have no technical aspect, in contrast with the provision disputed in *Barrie Public Utilities v. Canadian Cable Television Assn.*, [2003] 1 S.C.R. 476, 2003 SCC 28 (S.C.C.), at para. 86. The interpretation of general concepts such as "public interest" and "conditions" (as found in s. 15(3)(d) of the AEUBA) is not foreign to courts and is not derived from an area where the tribunal has been held to have greater expertise than the courts. The second question is whether the method and actual allocation in this case were reasonable. To resolve this issue, one must consider case law, policy justifications and the practice of other boards, as well as the details of the particular allocation in this case. The issue here is most likely characterized as one of mixed fact and law.

32 In light of the four factors, I conclude that each question requires a distinct standard of review. To determine the Board's power to allocate proceeds from a sale of utility assets suggests a standard of review of correctness. As expressed by the Court of Appeal, the focus of this inquiry remains on the particular provisions being invoked and interpreted by the tribunal (s. 26(2)(d) of the GUA and s. 15(3)(d) of the AEUBA) and "goes to jurisdiction" (*Pushpanathan*, at para. 28). Moreover, keeping in mind all the factors discussed, the generality of the proposition will be an additional factor in favour of the imposition of a correctness standard, as I stated in *Pushpanathan v. Canada (Minister of Employment & Immigration)*, at para. 38:

> ...the broader the propositions asserted, and the further the implications of such decisions stray from the core expertise of the tribunal, the less likelihood that deference will be shown. Without an implied or express legislative intent to the contrary as manifested in the criteria above, legislatures should be assumed to have left highly generalized propositions of law to courts.

33 The second question regarding the Board's actual method used for the allocation of proceeds likely attracts a more deferential standard. On the one hand, the Board's expertise, particularly in this area, its broad mandate, the technical nature of the question and the general purposes of the legislation, all suggest a relatively high level of deference to the Board's decision. On the other hand, the absence of a privative clause on questions of jurisdiction and the reference to law needed to answer this question all suggest a less deferential standard of review which favours reasonableness. It is not necessary, however, for me to determine which specific standard would have applied here.

34 As will be shown in the analysis below, I am of the view that the Court of Appeal made no error of fact or law when it concluded that the Board acted beyond its jurisdiction by misapprehending its statutory and common law authority. However, the Court of Appeal erred when it did not go on to conclude that the Board has no jurisdiction to allocate *any* portion of the proceeds of sale of the property to ratepayers.

2.3 Was the Board's Decision as to its Jurisdiction Correct?

35 Administrative tribunals or agencies are statutory creations: they cannot exceed the powers that were granted to them by their enabling statute; they must "adhere to the confines of their statutory authority or 'jurisdiction'[; and t]hey cannot trespass in areas where the legislature has not assigned them authority": Mullan, at pp. 9-10 (see also S. Blake, *Administrative Law in Canada*, (3rd ed. 2001), at pp. 183-184).

36 In order to determine whether the Board's decision that it had the jurisdiction to allocate proceeds from the sale of a utility's asset was correct, I am required to interpret the legislative framework by which the Board derives its powers and actions.

2.3.1 General Principles of Statutory Interpretation

37 For a number of years now, the Court has adopted E. A. Driedger's modern approach as the method to follow for statutory interpretation (*Construction of Statutes* (2nd ed. 1983), at p. 87):

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

(See, e.g., see *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27 (S.C.C.), at para. 21; *Bell ExpressVu Ltd. Partnership v. Rex*, [2002] 2 S.C.R. 559, 2002 SCC 42 (S.C.C.), at para. 26; *L. (H.) v. Canada (Attorney General)*, [2005] 1 S.C.R. 401, 2005 SCC 25 (S.C.C.), at paras. 186-87; *Marche v. Halifax Insurance Co.* (2005), 1 S.C.R. 47, 2005 SCC 6 (S.C.C.), at para. 54; *Barrie Public Utilities*, at paras. 20 and 86; *Contino v. Leonelli-Contino*, 2005 SCC 63 (S.C.C.), at para. 19.)

38 But more specifically in the area of administrative law, tribunals and boards obtain their jurisdiction over matters from two sources: 1) express grants of jurisdiction under various statutes (explicit powers); and 2) the common law, by application of the doctrine of jurisdiction by necessary implication (implicit powers) (see also D. M. Brown, *Energy Regulation in Ontario* (loose-leaf ed.), at p. 2-15).

39 The City submits that it is both implicit and explicit within the express jurisdiction that has been conferred upon the Board to approve or refuse to approve the sale of utility assets, that the Board can determine how to allocate the proceeds of the sale in this case. ATCO retorts that not only is such a power absent from the explicit language of the legislation, but it cannot be "implied" from the statutory regime as necessarily incidental to the explicit powers. I agree with ATCO's submissions and will elaborate in this regard.

2.3.2 Explicit Powers: Grammatical and Ordinary Meaning

40 As a preliminary submission, the City argues that given that ATCO applied to the Board for approval of both the sale transaction *and* the disposition of the proceeds of sale, this suggests that ATCO recognized that the Board has authority to allocate the proceeds as a condition of a proposed sale. This argument does not hold any weight in my view. First, the application for approval cannot be considered on its own an admission by ATCO of the jurisdiction of the Board. In any event, an admission of this nature would not have any bearing on the applicable law. Moreover, knowing that in the past the Board had decided that it had jurisdiction to allocate the proceeds of a sale of assets and had acted on this power, one can assume that ATCO was asking for the approval of the disposition of the proceeds should the Board not accept their argument on jurisdiction. In fact, a review of past Board decisions on the approval of sales shows that utility companies have constantly challenged the Board's jurisdiction to allocate the net gain on the sale of assets (see, e.g., *TransAlta Utilities Corp.*, Alta. E.U.B. Decision 2000-41; *ATCO Gas-North, A Division of ATCO Gas and Pipelines Ltd.*, Alta. E.U.B. Decision 2001-65; *Alberta Government Telephones* (1984), Alta. P.U.B. Decision No. E84081; *TransAlta Utilities Corp.* (1984), Alta. P.U.B. Decision No. E84116; *TransAlta Utilities Corp., Re* (Alta. E.U.B.); *ATCO Electric Ltd., Re* (Alta. E.U.B.)).

41 The starting point of the analysis requires that the Court examine the ordinary meaning of the sections at the centre of the dispute, s. 26(2)(d)(i) of the GUA, ss. 15(1) and (3)(d) of the AEUBA and s. 37 of the PUBA. For ease of reference, I reproduce these provisions:

GUA

26. ...

(2) No owner of a gas utility designated under subsection (1) shall

. . . . .

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them

. . . . .

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

AEUBA

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB [Energy Resources Conservation Board] and the PUB [Public Utilities Board] that are granted or provided for by any enactment or by law.

. . . . .

(3) Without restricting subsection (1), the Board may do all or any of the following:

. . . . .

(d) with respect to an order made by the Board, the ERCB or the PUB in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

. . . . .

PUBA

37 In matters within its jurisdiction the Board may order and require any person or local authority to do forthwith or within or at a specified time and in any manner prescribed by the Board, so far as it is not inconsistent with this Act or any other Act conferring jurisdiction, any act, matter or thing that the person or local authority is or may be required to do under this Act or under any other general or special Act, and may forbid the doing or continuing of any act, matter or thing that is in contravention of any such Act or of any regulation, rule, order or direction of the Board.

42 Some of the above provisions are duplicated in the other two statutes (see, e.g., PUBA, ss. 85(1) and 101(2)(d)(i); GUA, s. 22(1); see Appendix).

43 There is no dispute that s. 26(2) of the GUA contains a prohibition against, among other things, the owner of a utility selling, leasing, mortgaging or otherwise disposing of its property outside of the ordinary course of business without the approval of the Board. As submitted by ATCO, the power conferred is to approve without more. There is no mention in s. 26 of the grounds for granting or denying approval or of the ability to grant conditional approval, let alone the power of the Board to allocate the net profit of an asset sale. I would note in passing that this power is sufficient to alleviate the fear expressed by the Board that the utility might be tempted to sell assets on which it might realize a large profit to the detriment of ratepayers if it could reap the benefits of the sale.

44 It is interesting to note that s. 26(2) does not apply to all types of sales (and leases, mortgages, dispositions, encumbrances, mergers or consolidations). It excludes sales in the ordinary course of the owner's business. If the statutory scheme was such that the Board had the power to allocate the proceeds of the sale of utility assets, as argued here, s. 26(2) would naturally apply to all sales of assets or, at a minimum, exempt only those sales below a certain value. It is apparent that allocation of sale proceeds to customers is not one of its purposes. In fact, s. 26(2) can only have limited, if any, application to non-utility assets not related to utility function (especially when the sale has passed the "no-harm" test). The provision can only be meant to ensure that the asset in question is indeed non-utility, so that its loss does not impair the utility function or quality.

45 Therefore, a simple reading of s. 26(2) of the GUA does permit one to conclude that the Board does not have the power to allocate the proceeds of an asset sale.

46 The City does not limit its arguments to s. 26(2); it also submits that the AEUBA, pursuant to s. 15(3), is an express grant of jurisdiction because it authorizes the Board to impose any condition to any order so long as the condition is necessary in the public interest. In addition, it relies on the general power in s. 37 of the PUBA for the proposition that the Board may, in any matter within its jurisdiction, make any order pertaining to that matter that is not inconsistent with any applicable statute. The intended meaning of these two provisions, however, is lost when the provisions are simply read in isolation as proposed

by the City: R. Sullivan, *Sullivan and Driedger on the Construction of Statutes* (4th ed. 2002), at p. 21; *Canadian Pacific Air Lines Ltd. v. C.A.L.P.A.*, [1993] 3 S.C.R. 724 (S.C.C.), at p. 735; *Marche*, at paras. 59-60; *Bristol-Myers Squibb Co. v. Canada (Attorney General)*, [2005] 1 S.C.R. 533, 2005 SCC 26 (S.C.C.), at para. 105). These provisions on their own are vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to an order it makes. Furthermore, the concept of "public interest" found in s. 15(3) is very wide and elastic; the Board cannot be given total discretion over its limitations.

47 While I would conclude that the legislation is silent as to the Board's power to deal with sale proceeds after the initial stage in the statutory interpretation analysis, because the provisions can nevertheless be said to reveal some ambiguity and incoherence, I will pursue the inquiry further.

48 This Court has stated on numerous occasions that the grammatical and ordinary sense of a section is not determinative and does not constitute the end of the inquiry. The Court is obliged to consider the total context of the provisions to be interpreted, no matter how plain the disposition may seem upon initial reading (see *Chieu v. Canada (Minister of Citizenship & Immigration)*, [2002] 1 S.C.R. 84, 2002 SCC 3 (S.C.C.) at para. 34; Sullivan, at pp. 20-21). I will therefore proceed to examine the purpose and scheme of the legislation, the legislative intent and the relevant legal norms.

2.3.3 Implicit Powers: Entire Context

49 The provisions at issue are found in statutes which are themselves components of a larger statutory scheme which cannot be ignored:

> As the product of a rational and logical legislature, the statute is considered to form a system. Every component contributes to the meaning as a whole, and the whole gives meaning to its parts: "each legal provision should be considered in relation to other provisions, as parts of a whole" ...
>
> (P.-A. Côté, *The Interpretation of Legislation in Canada* (3rd ed. 2000), at p. 308)

As in any statutory interpretation exercise, when determining the powers of an administrative body, courts need to examine the context that colours the words and the legislative scheme. The ultimate goal is to discover the clear intent of the legislature and the true purpose of the statute while preserving the harmony, coherence and consistency of the legislative scheme (*Bell ExpressVu*, at para. 27; see also *Interpretation Act*, R.S.A. 2000, c. I-8, s. 10 (in Appendix)). "[S]tatutory interpretation is the art of finding the legislative spirit embodied in enactments": *Bristol-Myers Squibb Co.*, at para. 102.

50 Consequently, a grant of authority to exercise a discretion as found in s. 15(3) of the AEUBA and s. 37 of the PUBA does not confer unlimited discretion to the Board. As submitted by ATCO, the Board's discretion is to be exercised 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 (see Sullivan, at pp. 154-55). In the same vein, it is useful to refer to the following passage from *Bell Canada v. Canada (Canadian Radio-Television & Telecommunications Commission)*, [1989] 1 S.C.R. 1722 (S.C.C.), at p. 1756:

> The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes.

51 The mandate of this Court is to determine and apply the intention of the legislature (*Bell ExpressVu*, at para. 62) without crossing the line between judicial interpretation and legislative drafting (see *R. v. McIntosh*, [1995] 1 S.C.R. 686 (S.C.C.), at para. 26; *Bristol-Myers Squibb Co.*, at para. 174). That being said, this rule allows for the application of the "doctrine of jurisdiction by necessary implication"; the powers conferred by an enabling statute are construed to include not only those expressly granted but also, by implication, all powers which are practically necessary for the accomplishment of the object intended to be secured by the statutory regime created by the legislature (see Brown, at p. 2-16.2; *Bell Canada*, at p. 1756).

Canadian courts have in the past applied the doctrine to ensure that administrative bodies have the necessary jurisdiction to accomplish their statutory mandate:

> When legislation attempts to create a comprehensive regulatory framework, the tribunal must have the powers which by practical necessity and necessary implication flow from the regulatory authority explicitly conferred upon it.

Dow Chemical Canada Inc. v. Union Gas Ltd. (1982), 141 D.L.R. (3d) 641 (Ont. Div. Ct.), at pp. 658-59, aff'd (1983), 42 O.R. (2d) 731 (Ont. C.A.) (see also *Interprovincial Pipe Line Ltd. v. Canada (National Energy Board)* (1977), [1978] 1 F.C. 601 (Fed. C.A.); *Canadian Broadcasting League v. Canada (Canadian Radio-Television & Telecommunications Commission)* (1982), [1983] 1 F.C. 182 (Fed. C.A.), aff'd. [1985] 1 S.C.R. 174 (S.C.C.)).

52 I understand the City's arguments to be as follows: 1) the customers acquire a right to the property of the owner of the utility when they pay for the service and are therefore entitled to a return on the profits made at the time of the sale of the property; and 2) the Board has, by necessity, because of its jurisdiction to approve or refuse to approve the sale of utility assets, the power to allocate the proceeds of the sale as a condition of its order. The doctrine of jurisdiction by necessary implication is at the heart of the City's second argument. I cannot accept either of these arguments which are, in my view, diametrically contrary to the state of the law. This is revealed when we scrutinize the entire context which I will now endeavour to do.

53 After a brief review of a few historical facts, I will probe into the main function of the Board, rate setting, and I will then explore the incidental powers which can be derived from the context.

2.3.3.1 Historical Background and Broader Context

54 The history of public utilities regulation in Alberta originated with the creation in 1915 of the Board of Public Utility Commissioners by *The Public Utilities Act*, S.A. 1915, c. 6. This statute was based on similar American legislation: H. R. Milner, "Public Utility Rate Control in Alberta" (1930), 8 *Can. Bar Rev.* 101, at p. 101. While the American jurisprudence and texts in this area should be considered with caution given that Canada and the United States have very different political and constitutional-legal regimes, they do shed some light on the issue.

55 Pursuant to *The Public Utilities Act*, the first public utility board was established as a three-member tribunal to provide general supervision of all public utilities (s. 21), to investigate rates (s. 23), to make orders regarding equipment (s. 24), and to require every public utility to file with it complete schedules of rates (s. 23). Of interest for our purposes, the 1915 statute also required public utilities to obtain the approval of the Board of Public Utility Commissioners before selling any property when outside the ordinary course of their business (s. 29(g)).

56 The Alberta Energy and Utilities Board was created in February 1995 by the amalgamation of the Energy Resources Conservation Board and the Public Utilities Board (see Canadian Institute of Resources Law, *Canada Energy Law Service: Alberta* (loose-leaf ed.), at p. 30-3101). Since then, all matters under the jurisdiction of the Energy Resources Conservation Board and the Public Utilities Board have been handled by the Alberta Energy and Utilities Board and are within its exclusive jurisdiction. The Board has all of the powers, rights and privileges of its two predecessor boards (AEUBA, ss. 13, 15(1); GUA, s. 59).

57 In addition to the powers found in the 1915 statute, which have remained virtually the same in the present PUBA, the Board now benefits from the following express powers to:

> 1. make an order respecting the improvement of the service or commodity (PUBA, s. 80(b))
>
> 2. approve the issue by the public utility of shares, stocks, bonds and other evidences of indebtedness (GUA, s. 26(2)(a)); PUBA, s. 101(2)(a));
>
> 3. approve the lease, mortgage, disposition or encumbrance of the public utility's property, franchises, privileges or rights (GUA, s. 26(2)(d)(i); PUBA, s. 101(2)(d)(i));

4. approve the merger or consolidation of the public utility's property, franchises, privileges or rights (GUA, s. 26(2)(d)(ii); PUBA, s. 101(2)(d)(ii)); and

5. authorize the sale or permit to be made on the public utility's book a transfer of any share of its capital stock to a corporation that would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the public utility (GUA, 27(1); PUBA, s. 102(1)).

58 It goes without saying that public utilities are very limited in the actions they can take, as evidenced from the above list. Nowhere is there a mention of the authority to allocate proceeds from a sale or the discretion of the Board to interfere with ownership rights.

59 Even in 1995 when the legislature decided to form the Alberta Energy and Utilities Board, it did not see fit to modify the PUBA or the GUA to provide the new Board with the power to allocate the proceeds of a sale even though the controversy surrounding this issue was full-blown (see, e.g., *Alberta Government Telephones* (1984), Alta. P.U.B. Decision No. E84081; *TransAlta Utilities Corp.* (1984), Alta. P.U.B. Decision No. E84116). It is a well-established principle that the legislature is presumed to have a mastery of existing law, both common law and statute law (see Sullivan, at pp. 154-55). It is also presumed to have known all of the circumstances surrounding the adoption of new legislation.

60 Although the Board may seem to possess a variety of powers and functions, it is manifest from a reading of the AEUBA, the PUBA and the GUA that the principal function of the Board in respect of public utilities is the determination of rates. Its power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates (see Milner, at p. 102; Brown, at p. 2-16.6). Estey J., speaking for the majority of this Court in *Atco Ltd.*, at p. 576, echoed this view when he said:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities. Such an extensive regulatory pattern must, for its effectiveness, include the right to control the combination or, as the legislature says, "the union" of existing systems and facilities. <u>This no doubt has a direct relationship with the rate-fixing function which ranks high in the authority and functions assigned to the Board</u> [Emphasis added.]

In fact, even the Board itself, on its website (http://www.eub.gov.ab.ca/BBS/eubinfo/default.htm), describes its functions as follows:

> We regulate the safe, responsible, and efficient development of Alberta's energy resources: oil, natural gas, oil sands, coal, and electrical energy; and the pipelines and transmission lines to move the resources to market. <u>On the utilities side, we regulate rates and terms of service of investor-owned natural gas</u>, electric, and water utility services, as well the major intra-Alberta gas transmission system, <u>to ensure that customers receive safe and reliable service at just and reasonable rates</u>. [Emphasis added.]

61 The process by which the Board sets the rates is therefore central and deserves some attention in order to ascertain the validity of the City's first argument.

2.3.3.2 Rate Setting

62 Rate regulation serves several aims — sustainability, equity and efficiency — which underlie the reasoning as to how rates are fixed:

> ...the regulated company must be able to finance its operations, and any required investment, so that it can continue to operate in the future. Equity is related to the distribution of welfare among members of society. The objective of sustainability already implies that shareholders should not receive "too low" a return (and defines this in terms of the reward necessary to ensure continued investment in the utility), while equity implies that their returns should not be "too high".

> (R. Green and M. Rodriguez Pardina, *Resetting Price Controls for Privatized Utilities: A Manual for Regulators* (1999), at p. 5)

63 These goals have resulted in an economic and social arrangement dubbed the "regulatory compact", which ensures that all customers have access to the utility at a fair price - nothing more. As I will further explain, it does not transfer onto the customers any property right. Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated (see Black, at pp. 356-57; Milner, at p. 101; *Atco*, at p. 576; *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.), at pp. 192-93 (hereinafter "*Northwestern 1929*")).

64 Therefore, when interpreting the broad powers of the Board, one cannot ignore this well-balanced regulatory arrangement which serves as a backdrop for contextual interpretation. The object of the statutes is to protect both the customer *and* the investor (Milner, at p. 101). The arrangement does not, however, cancel the private nature of the utility. In essence, the Board is responsible for maintaining a tariff that enhances the economic benefits to consumers and investors of the utility.

65 The Board derives its power to set rates from both the GUA (ss. 16, 17 and 36 to 45) and the PUBA (ss. 89 to 95). The Board is mandated to fix "just and reasonable ... rates" (PUBA, s. 89(a), GUA, s. 36(a)). In the establishment of these rates, the Board is directed to "determine a rate base for the property of the owner" and "fix a fair return on the rate base" (GUA, s. 37(1)). This Court, in *Northwestern Utilities Ltd. v. Edmonton (City)* (1978), [1979] 1 S.C.R. 684 (S.C.C.), at p. 691 (hereinafter "*Northwestern 1979*"), adopted the following description of the process:

> The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. In Phase I the PUB determines the rate base, that is the amount of money which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered.

(See also *Re Gas Utilities Act and Public Utilities Board Act* (1984), Alta. P.U.B. Decision No. E84113, at p. 23; *Union Gas Ltd. v. Ontario (Energy Board)* (1983), 1 D.L.R. (4th) 698 (Ont. Div. Ct.), at pp. 701-702.)

66 Consequently, when determining the rate base, the Board is to give due consideration (GUA, s. 37(2)):

> (a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
>
> (b) to necessary working capital.

67 The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. In fact, the wording of the sections quoted above suggests that the ownership of the assets is clearly that of the utility; ownership of the asset and entitlement to profits or losses upon its realization are one and the same. The equity investor expects to receive the net revenues after all costs are paid, equal to the present value of original investment at the time of that investment. The disbursement of some portions of the residual amount of net revenue, by after-the-fact reallocation to rate-paying customers, undermines that investment process: MacAvoy and Sidak, at p. 244. In fact, speculation would accrue even more often should the public utility, through its shareholders, not be the one to benefit from

the possibility of a profit, as investors would expect to receive a larger premium for their funds through the only means left available, the return on their original investment. In addition, they would be less willing to accept any risk.

68 Thus, can it be said, as alleged by the City, that the customers have a property interest in the utility? Absolutely not: that cannot be so, as it would mean that fundamental principles of corporate law would be distorted. Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources. They do not by their payment implicitly purchase the asset from the utility's investors. The payment does not incorporate acquiring ownership or control of the utility's assets. The ratepayer covers the cost of using the service, not the holding cost of the assets themselves: "A utility's customers are not its owners, for they are not residual claimants": MacAvoy and Sidak, at p. 245 (see also p. 237). Ratepayers have made no investment. Shareholders have and they assume all risks as the residual claimants to the utility's profit. Customers have only "the risk of a price change resulting from any (authorized) change in the cost of service. This change is determined only periodically in a tariff review by the regulator" (MacAvoy and Sidak, p. 245).

69 In this regard, I agree with ATCO when it asserts in its factum, at para. 38:

> The property in question is as fully the private property of the owner of the utility as any other asset it owns. Deployment of the asset in utility service does not create or transfer any legal or equitable rights in that property for ratepayers. Absent any such interest, any taking such as ordered by the Board is confiscatory...

Wittmann J.A., at the Court of Appeal, said it best when he stated:

> Consumers of utilities pay for a service, but by such payment, do not receive a proprietary right in the assets of the utility company. Where the calculated rates represent the fee for the service provided in the relevant period of time, ratepayers do not gain equitable or legal rights to non-depreciable assets when they have paid only for the use of those assets. [Emphasis added; para. 64.]

I fully adopt this conclusion. The Board misdirected itself by confusing the interests of the customers in obtaining safe and efficient utility service with an interest in the underlying assets owned only by the utility. While the utility has been compensated for the services provided, the customers have provided no compensation for receiving the benefits of the subject property. The argument that assets purchased are reflected in the rate base should not cloud the issue of determining who is the appropriate owner and risk bearer. Assets are indeed considered in rate setting, as a factor, and utilities cannot sell an asset used in the service to create a profit and thereby restrict the quality or increase the price of service. Despite the consideration of utility assets in the rate-setting process, shareholders are the ones solely affected when the actual profits or losses of such a sale are realized; the utility absorbs losses and gains, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality. There can be a default risk affecting ratepayers, but this does not make ratepayers residual claimants. While I do not wish to unduly rely on American jurisprudence, I would note that the leading U.S. case on this point is *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (U.S. S.C. 1989), which relies on the same principle as was adopted in *Market St. Ry. Co. v. Railroad Commission California*, 324 U.S. 548 (U.S. S.C. 1945).

70 Furthermore, one has to recognize that utilities are not Crown entities, fraternal societies or cooperatives, or mutual companies, although they have a "public interest" aspect which is to supply the public with a necessary service (in the present case, the provision of natural gas). The capital invested is not provided by the public purse or by the customers; it is injected into the business by private parties who expect as large a return on the capital invested in the enterprise as they would receive if they were investing in other securities possessing equal features of attractiveness, stability and certainty (see *Northwestern 1929*, at p. 192). This prospect will necessarily include any gain or loss that is made if the company divests itself of some of its assets, i.e., land, buildings, etc.

71 From my discussion above regarding the property interest, the Board was in no position to proceed with an implicit refund by allocating to ratepayers the profits from the asset sale because it considered ratepayers had paid excessive rates for services in the past. As such, the City's first argument must fail. The Board was seeking to rectify what it perceived as a historic

over-compensation to the utility by ratepayers. There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation. It is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates (*Northwestern 1979*, at p. 691; *Coseka Resources Ltd. v. Saratoga Processing Co.* (1980), 126 D.L.R. (3d) 705 (Alta. C.A.), at p. 715, leave to appeal refused, [1981] 2 S.C.R. vii (S.C.C.); *Dow Chemical Canada Inc.*, at pp. 734-35). But more importantly, it cannot even be said that there was over-compensation: the rate-setting process is a speculative procedure in which both the ratepayers and the shareholders jointly carry their share of the risk related to the business of the utility (see MacAvoy and Sidak, at pp. 238-39).

2.3.3.3 The Power to Attach Conditions

72 As its second argument, the City submits that the power to allocate the proceeds from the sale of the utility's assets is necessarily incidental to the express powers conferred on the Board by the AEUBA, the GUA and the PUBA. It argues that the Board must necessarily have the power to allocate sale proceeds as part of its discretionary power to approve or refuse to approve a sale of assets. It submits that this results from the fact that the Board is allowed to attach any condition to an order it makes approving such a sale. I disagree.

73 The City seems to assume that the doctrine of jurisdiction by necessary implication applies to "broadly drawn powers" as it does for "narrowly drawn powers"; this cannot be. The Ontario Energy Board in its decision in *Re Consumers' Gas Co.* (1987), E.B.R.O. 410-II/411-II/412-II, at para. 4.73, enumerated the circumstances when the doctrine of jurisdiction by necessary implication may be applied:

> 1. when the jurisdiction sought is necessary to accomplish the objects of the legislative scheme and is essential to the Board fulfilling its mandate;
>
> 2. when the enabling act fails to explicitly grant the power to accomplish the legislative objective;
>
> 3. when the mandate of the Board is sufficiently broad to suggest a legislative intention to implicitly confer jurisdiction;
>
> 4. when the jurisdiction sought is not one which the Board has dealt with through use of expressly granted powers, thereby showing an absence of necessity; and
>
> 5. when the legislature did not address its mind to the issue and decide against conferring the power to the Board.
> (See also Brown, at p. 2-16.3.)

74 In light of the above, it is clear that the doctrine of jurisdiction by necessary implication will be of less help in the case of broadly drawn powers than for narrowly drawn ones. Broadly drawn powers will necessarily be limited to only what is rationally related to the purpose of the regulatory framework. This is explained by Professor Sullivan, at p. 228:

> In practice, however, purposive analysis makes the powers conferred on administrative bodies almost infinitely elastic. Narrowly drawn powers can be understood to include "by necessary implication" all that is needed to enable the official or agency to achieve the purpose for which the power was granted. Conversely, broadly drawn powers are understood to include only what is rationally related to the purpose of the power. In this way the scope of the power expands or contracts as needed, in keeping with the purpose. [Emphasis added.]

75 In the case at bar, s. 15 of the AEUBA, which allows the Board to impose additional conditions when making an order, appears at first glance to be a power having infinitely elastic scope. However, in my opinion, the attempt by the City to use it to augment the powers of the Board in s. 26(2) of the GUA must fail. The Court must construe s. 15(3) of the AEUBA in accordance with the purpose of s. 26(2).

76 MacAvoy and Sidak, in their article, at pp. 234-36, suggest three broad reasons for the requirement that a sale must be approved by the Board:

1. It prevents the utility from degrading the quality, or reducing the quantity, of the regulated service so as to harm consumers;

2. It ensures that the utility maximizes the aggregate economic benefits of its operations, and not merely the benefits flowing to some interest group or stakeholder; and

3. It specifically seeks to prevent favoritism toward investors.

77 Consequently, in order to impute jurisdiction to a regulatory body to allocate proceeds of a sale, there must be evidence that the exercise of that power is a practical necessity for the regulatory body to accomplish the objects prescribed by the legislature, something which is absent in this case (see *Reference re National Energy Board Act*, [1986] 3 F.C. 275 (Fed. C.A.)). In order to meet these three goals, it is not necessary for the Board to have control over which party should benefit from the sale proceeds. The public interest component cannot be said to be sufficient to impute to the Board the power to allocate all the profits pursuant to the sale of assets. In fact, it is not necessary for the Board in carrying out its mandate to order the utility to surrender the bulk of the proceeds from a sale of its property in order for that utility to obtain approval for a sale. The Board has other options within its jurisdiction which do not involve the appropriation of the sale proceeds, the most obvious one being to refuse to approve a sale that will, in the Board's view, affect the quality and/or quantity of the service offered by the utility or create additional operating costs for the future. This is not to say that the Board can never attach a condition to the approval of sale. For example, the Board could approve the sale of the assets on the condition that the utility company gives undertakings regarding the replacement of the assets and their profitability. It could also require as a condition that the utility reinvest part of the sale proceeds back into the company in order to maintain a modern operating system that achieves the optimal growth of the system.

78 In my view, allowing the Board to confiscate the net gain of the sale under the pretence of protecting rate-paying customers and acting in the "public interest" would be a serious misconception of the powers of the Board to approve a sale; to do so would completely disregard the economic rationale of rate setting, as I explained earlier in these reasons. Such an attempt by the Board to appropriate a utility's excess net revenues for ratepayers would be highly sophisticated opportunism and would, in the end, simply increase the utility's capital costs (MacAvoy and Sidak, at p. 246). At the risk of repeating myself, a public utility is first and foremost a private business venture which has as its goal the making of profits. This is not contrary to the legislative scheme, even though the regulatory compact modifies the normal principles of economics with various restrictions explicitly provided for in the various enabling statutes. None of the three statutes applicable here provides the Board with the power to allocate the proceeds of a sale and therefore affect the property interests of the public utility.

79 It is well established that potentially confiscatory legislative provision ought to be construed cautiously so as not to strip interested parties of their rights without the clear intention of the legislation (see Sullivan, at pp. 400-403; Côté, at pp. 482-86; *Pacific National Investments Ltd. v. Victoria (City)*, [2000] 2 S.C.R. 919, 2000 SCC 64 (S.C.C.), at para. 26; *Leiriao c. Val-Bélair (Ville)*, [1991] 3 S.C.R. 349 (S.C.C.), at p. 357; *Hongkong Bank of Canada v. Wheeler Holdings Ltd.*, [1993] 1 S.C.R. 167 (S.C.C.), at p. 197). Not only is the authority to attach a condition to allocate the proceeds of a sale to a particular party unnecessary for the Board to accomplish its role, but deciding otherwise would lead to the conclusion that a broadly drawn power can be interpreted so as to encroach on the economic freedom of the utility, depriving it of its rights. This would go against the above principles of interpretation.

80 If the Alberta legislature wishes to confer on ratepayers the economic benefits resulting from the sale of utility assets, it can expressly provide for this in the legislation, as was done by some states in the United States (e.g., Connecticut).

2.4 Other Considerations

81 Under the regulatory compact, customers are protected through the rate-setting process, under which the Board is required to make a well-balanced determination. The record shows that the City did not submit to the Board a general rate review application in response to ATCO's application requesting approval for the sale of the property at issue in this case. Nonetheless, if it chose to do so, this would not have stopped the Board, on its own initiative, from convening a hearing of the interested

parties in order to modify and fix just and reasonable rates to give due consideration to any new economic data anticipated as a result of the sale (PUBA, s. 89(a); GUA, ss. 24, 36(a), 37(3), 40) (see Appendix).

2.5 If Jurisdiction Had Been Found, Was the Board's Allocation Reasonable?

82 In light of my conclusion with regard to jurisdiction, it is not necessary to determine whether the Board's exercise of discretion by allocating the sale proceeds as it did was reasonable. Nonetheless, given the reasons of my colleague Binnie J., I will address the issue very briefly. Had I not concluded that the Board lacked jurisdiction, my disposition of this case would have been the same, as I do not believe the Board met a reasonable standard when it exercised its power.

83 I am not certain how one could conclude that the Board's allocation was reasonable when it wrongly assumed that ratepayers had acquired a proprietary interest in the utility's assets because assets were a factor in the rate-setting process, and, moreover, when it explicitly concluded that no harm would ensue to customers from the sale of the asset. In my opinion, when reviewing the substance of the Board's decision, a court must conduct a two-step analysis: first, it must determine whether the order was warranted given the role of the Board to *protect the customers*, (i.e., was the order *necessary in the public interest?*); and second, if the first question is answered in the affirmative, a court must then examine the validity of the Board's application of the *TransAlta Formula* (see para. 12 of these reasons), which refers to the difference between net book value and original cost, on the one hand, and appreciation in the value of the asset on the other. For the purposes of this analysis, I view the second step as a mathematical calculation and nothing more. I do not believe it provides the criteria which guides the Board to determine *if it should allocate* part of the sale proceeds to ratepayers. Rather, it merely guides the Board on *what to allocate and how to allocate* it (if it should do so in the first place). It is also interesting to note that there is no discussion of the fact that the book value used in the calculation must be referable solely to the financial statements of the utility.

84 In my view, as I have already stated, the power of the Board to allocate proceeds does not even arise in this case. Even by the Board's own reasoning, it should only exercise its discretion to act in the public interest when customers would be harmed or would face some risk of harm. But the Board was clear: there was no harm or risk of harm in the present situation (Decision 2002-037; para. 54):

> With the continuation of the same level of service at other locations and the acceptance by customers regarding the relocation, the Board is convinced there should be no impact on the level of service to customers as a result of the Sale. In any event, the Board considers that the service level to customers is a matter that can be addressed and remedied in a future proceeding if necessary.

After declaring that the customers would not, on balance, be harmed, the Board maintained that, on the basis of the evidence filed, there appeared to be a cost savings to the customers. There was no legitimate customer interest which could or needed to be protected by denying approval of the sale, or by making approval conditional on a particular allocation of the proceeds. Even if the Board had found a possible adverse effect arising from the sale, how could it allocate proceeds now based on an unquantified future potential loss? Moreover, in the absence of any factual basis to support it, I am also concerned with the presumption of bad faith on the part of ATCO that appears to underlie the Board's determination to protect the public from some possible future menace. In any case, as mentioned earlier in these reasons, this determination to protect the public interest is also difficult to reconcile with the actual power of the Board to prevent harm to ratepayers from occurring by simply refusing to approve the sale of a utility's asset. To that, I would add that the Board has considerable discretion in the setting of future rates in order to protect the public interest, as I have already stated.

85 In consequence, I am of the view that, in the present case, the Board did not identify any public interest which required protection and there was, therefore, nothing to trigger the exercise of the discretion to allocate the proceeds of sale. Hence, notwithstanding my conclusion on the first issue regarding the Board's jurisdiction, I would conclude that the Board's decision to exercise its discretion to protect the public interest did not meet a reasonable standard.

3. Conclusion

86 This Court's role in this case has been one of interpreting the enabling statutes using the appropriate interpretive tools, i.e. context, legislative intention and objective. Going further than required by reading in *unnecessary* powers of an administrative agency under the guise of statutory interpretation is not consistent with the rules of statutory interpretation. It is particularly dangerous to adopt such an approach when property rights are at stake.

87 The Board did not have the jurisdiction to allocate the proceeds of the sale of the utility's asset; its decision did not meet the correctness standard. Thus, I would dismiss the City's appeal and allow ATCO's cross-appeal, both with costs. I would also set aside the Board's decision and refer the matter back to the Board to approve the sale of the property belonging to ATCO, recognizing that the proceeds of the sale belong to ATCO.

***Binnie J.*:**

88 The respondent ATCO Gas and Pipelines Ltd. ("ATCO") is part of a large entrepreneurial company that directly and through various subsidiaries operates both regulated businesses and unregulated businesses. The Alberta Energy and Utilities Board (the "Board") believes it not to be in the public interest to encourage utility companies to mix together the two types of undertakings. In particular, the Board has adopted policies to discourage utilities from using their regulated businesses as a platform to engage in land speculation to increase their return on investment outside the regulatory framework. By awarding part of the profit to the utility (and its shareholders), the Board rewards utilities for diligence in divesting themselves of assets that are no longer productive, or that could be more productively employed elsewhere. However, by crediting part of the profit on the sale of such property to the utility's rate base (i.e. as a set-off to other costs), the Board seeks to dampen any incentive for utilities to skew decisions in their regulated business to favour such profit taking unduly. Such a balance, in the Board's view, is necessary in the interest of the public which allows ATCO to operate its utility business as a monopoly. In pursuit of this balance, the Board approved ATCO's application to sell land and warehousing facilities in downtown Calgary, but denied ATCO's application to keep for its shareholders the entire profit resulting from appreciation in the value of the land, whose cost of acquisition had formed part of the rate base on which gas rates had been calculated since 1922. The Board ordered the profit on the sale to be allocated one third to ATCO and two thirds as a credit to its cost base, thereby helping keep utility rates down, and to that extent benefiting ratepayers.

89 I have read with interest the reasons of my colleague Bastarache J. but, with respect, I do not agree with his conclusion. As will be seen, the Board has authority under s. 15(3) of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 ("AEUBA") to impose on the sale "any additional conditions that the Board considers necessary in the public interest". Whether or not the conditions of approval imposed by the Board were necessary in the public interest was for the Board to decide. The Alberta Court of Appeal overruled the Board but, with respect, the Board is in a better position to assess necessity in this field for the protection of the public interest than either that court or this Court. I would allow the appeal and restore the Board's decision.

I. Analysis

90 ATCO's argument boils down to the proposition announced at the outset of its factum:

> In the absence of any property right or interest and of any harm to the customers arising from the withdrawal from utility service, there was no proper ground for reaching into the pocket of the utility. In essence this case is about property rights.
>
> (Respondent's factum, para. 2)

91 For the reasons which follow I do not believe the case is about property rights. ATCO chose to make its investment in a regulated industry. The return on investment in the regulated gas industry is fixed by the Board, not the free market. In my view, the essential issue is whether the Alberta Court of Appeal was justified in limiting what the Board is allowed to "conside[r] necessary in the public interest".

A. The Board's Statutory Authority

92 The first question is one of jurisdiction. What gives the Board the authority to make the order ATCO complains about? The Board's answer is threefold. Section 22(1) of the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("GUA") provides in part that "[t]he Board shall exercise a general supervision over all gas utilities, and the owners of them...". This, the Board says, gives it a broad jurisdiction to set policies that go beyond its specific powers in relation to specific applications, such as rate setting. Of more immediate pertinence, s. 26(2)(d)(i) of the same Act prohibits the regulated utility from selling, leasing or otherwise encumbering any of its property without the Board's approval. (To the same effect, see s. 101(2)(d)(i) of the *Public Utilities Board Act*, R.S.A. 2000, c. P-45.) It is common ground that this restraint on alienation of property applies to the proposed sale of ATCO's land and warehouse facilities in downtown Calgary, and that the Board could, in appropriate circumstances, simply have denied ATCO's application for approval of the sale. However, the Board was of the view to allow the sale subject to conditions. The Board ruled that the greater power (i.e. to deny the sale) must include the lesser (i.e. to allow the sale, subject to conditions) (Decision 2002-037, (Alta. E.U.B.), para. 47).

> In appropriate circumstances, the Board clearly has the power to prevent a utility from disposing of its property. In the Board's view it also follows that the Board can approve a disposition subject to appropriate conditions to protect customer interests.

There is no need to rely on any such implicit power to impose conditions, however. As stated, the Board's explicit power to impose conditions is found in s. 15(3) of the AEUBA, which authorizes the Board to "make any further order and impose any additional conditions that the Board considers necessary in the public interest". In *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557 (S.C.C.), at p. 576, Estey, J., for the majority, stated:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board <u>a mandate of the widest proportions to safeguard the public interest</u> in the nature and quality of the service provided to the community by the public utilities. [Emphasis added.]

The legislature says in s. 15(3) that the conditions are to be what *the Board* considers necessary. Of course, the discretionary power to impose conditions thus granted is not unlimited. It must be exercised in good faith for its intended purpose: *C.U.P.E. v. Ontario (Minister of Labour)*, [2003] 1 S.C.R. 539, 2003 SCC 29 (S.C.C.). ATCO says the Board overstepped even these generous limits. In ATCO's submission:

> Deployment of the asset in utility service does not create or transfer any legal or equitable rights in that property for ratepayers. Absent any such interest, any taking such as ordered by the Board is confiscatory.
>
> (Respondent's factum, para. 38)

In my view, however, the issue before the Board was how much profit ATCO was entitled to earn on its investment in a regulated utility.

93 ATCO argues in the alternative that the Board engaged in impermissible "retroactive rate making". But Alberta is an "original cost" jurisdiction, and no one suggests that the Board's original cost rate making during the 80-plus years this investment has been reflected in ATCO's ratebase was wrong. The Board proposed to apply a portion of the expected profit to future rate making. The effect of the order is prospective, not retroactive. Fixing the going-forward rate of return as well as general supervision of "all gas utilities, and the owners of them" were matters squarely within the Board's statutory mandate.

B. The Board's Decision

94 ATCO argues that the Board's decision should be seen as a stand-alone decision divorced from its rate making responsibilities. However, I do not agree that the hearing under s. 26 of the GUA can be isolated in this way from the Board's general regulatory responsibilities. ATCO argues in its factum that

> ...the subject application by [ATCO] to the Board did not concern or relate to a rate application, and the Board was not engaged in fixing rates (if that could provide any justification, which is denied).

> (Respondent's factum, para. 98)

95 It seems the Board proceeded with the s. 26 approval hearing separately from a rate setting hearing firstly because ATCO framed the proceeding in that way and secondly because this is the procedure approved by the Alberta Court of Appeal in *Transalta Utilities Corp. v. Alberta (Public Utilities Board)* (1986), 68 A.R. 171 (Alta. C.A.). That case (which I will refer to as *Transalta (1986)*) is a leading Alberta authority dealing with the allocation of the gain on the disposal of utility assets and the source of what is called the *TransAlta Formula* applied by the Board in this case. Kerans J.A. had this to say, at p. 174.

> I observe parenthetically that I now appreciate that it suits the convenience of everybody involved to resolve issues of this sort, if possible, before a general rate hearing so as to lessen the burden on that already complex procedure.

96 Given this encouragement from the Alberta Court of Appeal, I would place little significance on ATCO's procedural point. As will be seen, the Board's ruling is directly tied into the setting of general rates because two thirds of the profit is taken into account as an offset to ATCO's costs from which its revenue requirement is ultimately derived. As stated, ATCO's profit on the sale of the Calgary property will be a current (not historical) receipt and, if the Board has its way, two thirds of it will be applied to future (not retroactive) rate making.

97 The s. 26 hearing proceeded in two phases. The Board first determined that it would not deny its approval to the proposed sale as it met a "no-harm test" devised over the years by Board practice (it is not to be found in the statutes) (Decision 2001-78). However, the Board linked its approval to subsequent consideration of the financial ramifications, as the Board itself noted (Decision 2002-037):

> The Board approved the Sale in Decision 2001-78 based on evidence that customers did not object to the Sale [and] would not suffer a reduction in services <u>nor would they be exposed to the risk of financial harm as a result of the Sale *that could not be examined in a future proceeding*. On that basis.</u> the Board determined that the no-harm test had been satisfied and that the Sale could proceed. [Emphasis added; para. 13.]

98 In effect, ATCO ignores the italicized words. It argues that the Board was *functus* after the first phase of its hearing. However, ATCO itself had agreed to the two-phase procedure, and indeed the second phase was devoted to ATCO's own application for an allocation of the profits on the sale.

99 In the second phase of the s. 26 approval hearing, the Board allocated one third of the net gain to ATCO and two thirds to the rate base (which would benefit ratepayers). The Board spelled out why it considered these conditions to be necessary in the public interest. The Board explained that it was necessary to balance the interests of both shareholders and ratepayers within the framework of what it called "the regulatory compact" (Decision 2002-037, at para. 44). In the Board's view:

> (a) there ought to be a balancing of the interests of the ratepayers and the owners of the utility;
>
> (b) decisions made about the utility should be driven by both parties' interests;
>
> (c) to award the entire gain to the ratepayers would deny the utility an incentive to increase its efficiency and reduce its costs; and
>
> (d) to award the entire gain to the utility might encourage speculation in non-depreciable property or motivate the utility to identify and dispose of properties which have appreciated for reasons other than the best interest of the regulated business.

100 For purposes of this appeal, it is important to set out the Board's policy reasons in its own words:

> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.

> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred.
>
> The Board believes that some method of balancing both parties' interests will result in optimization of business objectives for both the customer and the company. Therefore, the Board considers that sharing of the net gain on the sale of the land and buildings collectively in accordance with the TransAlta Formula is equitable in the circumstances of this application and is consistent with past Board decisions. [Emphasis added; paras. 112-14.]

101 The Court was advised that the two-third share allocated to ratepayers would be included in ATCO's rate calculation to set off against the costs included in the rate base and amortized over a number of years.

C. Standard of Review

102 The Court's modern approach to this vexed question was recently set out by McLachlin C.J. in *Q. v. College of Physicians & Surgeons (British Columbia)*, [2003] 1 S.C.R. 226, 2003 SCC 19 (S.C.C.), at para. 26:

> In the pragmatic and functional approach, the standard of review is determined by considering four contextual factors — the presence or absence of a privative clause or statutory right of appeal; the expertise of the tribunal relative to that of the reviewing court on the issue in question; the purposes of the legislation and the provision in particular; and, the nature of the question — law, fact, or mixed law and fact. The factors may overlap. The overall aim is to discern legislative intent, keeping in mind the constitutional role of the courts in maintaining the rule of law.

103 I do not propose to cover the ground already set out in the reasons of my colleague Bastarache J. We agree that the standard of review on matters of jurisdiction is correctness. We also agree that the Board's *exercise* of its jurisdiction calls for greater judicial deference. Appeals from the Board are limited to questions of law or jurisdiction. The Board knows a great deal more than the courts about gas utilities, and what limits it is necessary to impose "in the public interest" on their dealings with assets whose cost is included in the rate base. Moreover, it is difficult to think of a broader discretion than that conferred on the Board to "impose any additional conditions that *the Board* considers necessary *in the public interest*". The identification of a subjective discretion in the decision maker ("the Board considers necessary"), the expertise of that decision maker and the nature of the decision to be made ("in the public interest"), in my view, call for the most deferential standard, patent unreasonableness.

104 As to the phrase "the Board considers necessary", Martland J. stated in *Calgary Power Ltd. v. Copithorne* (1958), [1959] S.C.R. 24 (S.C.C.), at p. 34:

> The question as to whether or not the respondent's lands were "necessary" is not one to be determined by the Courts in this case. The question is whether the Minister "deemed" them to be necessary.

See also D. J. M. Brown and J. M. Evans, *Judicial Review of Administrative Action in Canada* (loose-leaf ed.), vol. 1, at para. 14:2622: "*Objective" and "Subjective" Grants of Discretion*.

105 The expert qualifications of a regulatory Board are of "utmost importance in determining the intention of the legislator with respect to the degree of deference to be shown to a tribunal's decision in the absence of a full privative clause", as stated by Sopinka J. in *C.J.A., Local 579 v. Bradco Construction Ltd.*, [1993] 2 S.C.R. 316 (S.C.C.), at p. 335. He continued:

> Even where the tribunal's enabling statute provides explicitly for appellate review, as was the case in *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722], it has been stressed that deference should be shown by the appellate tribunal to the opinions of the specialized lower tribunal on matters squarely within its jurisdiction.

(This *dictum* was cited with approval in *Pezim v. British Columbia (Superintendent of Brokers)*, [1994] 2 S.C.R. 557 (S.C.C.), at p. 592.)

106 A regulatory power to be exercised "in the public interest" necessarily involves accommodation of conflicting economic interests. It has long been recognized that what is "in the public interest" is not really a question of law or fact but is an opinion. In *Transalta (1986)*, the Alberta Court of Appeal (at para. 24) drew a parallel between the scope of the words "public interest" and the well-known phrase "public convenience and necessity" in its citation of *Memorial Gardens Assn. (Canada) Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353 (S.C.C.), where this Court stated, at p. 357:

> [T]he question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding, in the public interest, ... [Emphasis added.]

107 This passage reiterated the *dictum* of Rand J. in *Union Gas Co. of Canada v. Sydenham Gas & Petroleum Co.*, [1957] S.C.R. 185 (S.C.C.), at p. 190:

> It was argued, and it seems to have been the view of the Court, that the determination of public convenience and necessity was itself a question of fact, but with that I am unable to agree: it is not an objective existence to be ascertained; the determination is the formulation of an opinion, in this case, the opinion of the Board and of the Board only. [Emphasis added.]

108 Of course even such a broad power is not untrammelled. But to say that such a power is capable of abuse does not lead to the conclusion that it should be truncated. I agree on this point with Reid J. (co-author of R.F. Reid and H. David, *Administrative Law and Practice* (2nd ed. 1978), and co-editor of P. Anisman and R. F. Reid, *Administrative Law Issues and Practice* (1995)) who wrote in *Canadian Tire Corp. v. C.T.C. Dealer Holdings Ltd.* (1987), 59 O.R. (2d) 79 (Ont. Div. Ct.), in relation to the powers of the Ontario Securities Commission, at p. 97:

> ...when the Commission has acted *bona fide*, with an obvious and honest concern for the public interest, and with evidence to support its opinion, the prospect that the breadth of its discretion might someday tempt it to place itself above the law by misusing that discretion is not something that makes the existence of the discretion bad *per se*, and requires the decision to be struck down.

(The *C.T.C. Dealer Holdings* decision was referred to with apparent approval by this Court in *Committee for Equal Treatment of Asbestos Minority Shareholders v. Ontario (Securities Commission)*, [2001] 2 S.C.R. 132, 2001 SCC 37 (S.C.C.), at para. 42.)

109 "Patent unreasonableness" is a highly deferential standard:

> A correctness approach means that there is only one proper answer. A patently unreasonable one means that there could have been many appropriate answers, but not the one reached by the decision maker.
>
> (*C.U.P.E.*, at para. 164)

110 Having said all that, in my view nothing much turns on the result on whether the proper standard in that regard is patent unreasonableness (as I view it) or simple reasonableness (as my colleague sees it). As will be seen, the Board's response is well within the range of established regulatory opinions. Hence, even if the Board's conditions were subject to the less deferential standard, I would find no cause for the Court to interfere.

D. Did the Board Have Jurisdiction to Impose the Conditions It Did on the Approval Order "In the Public Interest"?

111 ATCO says the Board had no jurisdiction to impose conditions that are "confiscatory". Framing the question in this way, however, assumes the point in issue. The correct point of departure is not to assume that ATCO is entitled to the net gain and then ask if the Board can confiscate it. ATCO's investment of $83,000 was added in increments to its regulatory cost base as

the land was acquired from time to time between 1922 and 1965. It is in the nature of a regulated industry that the question of what is a just and equitable return is determined by a board and not by the vagaries of the speculative property market.

112 I do not think the legal debate is assisted by talk of "confiscation". ATCO is prohibited by statute from disposing of the asset without Board approval, and the Board has statutory authority to impose conditions on its approval. The issue thus necessarily turns not on the *existence* of the jurisdiction but on the *exercise* of the Board's jurisdiction to impose the conditions that it did, and in particular to impose a shared allocation of the net gain.

E. Did the Board Improperly Exercise the Jurisdiction it Possessed to Impose Conditions the Board Considered "Necessary in the Public Interest"?

113 There is no doubt that there are many approaches to "the public interest". Which approach the Board adopts is largely (and inherently) a matter of opinion and discretion. While the statutory framework of utilities regulation varies from jurisdiction to jurisdiction, and practice in the United States must be read in light of the constitutional protection of property rights in that country, nevertheless Alberta's grant of authority to its Board is more generous than most. ATCO concedes that its "property" claim would have to give way to a contrary legislative intent, but ATCO says such intent cannot be found in the statutes.

114 Most if not all regulators face the problem of how to allocate gains on property whose original cost is included in the rate base but is no longer required to provide the service. There is a wealth of regulatory experience in many jurisdictions that the Board is entitled to (and does) have regard to in formulating its policies. Striking the correct balance in the allocation of gains between ratepayers and investors is a common preoccupation of comparable boards and agencies:

> First, it prevents the utility from degrading the quality, or reducing the quantity, of the regulated service so as to harm consumers. Second, it ensures that the utility maximizes the aggregate economic benefits of its operations, and not merely the benefits flowing to some interest group or stakeholder. Third, it specifically seeks to prevent favouritism toward investors to the detriment of ratepayers affected by the transaction.
>
> ("The Efficient Allocation of Proceeds from a Utility's Sale of Assets", by P. W. MacAvoy and J. G. Sidak (2001) 22 *Energy L.J.* 233, at p. 234)

115 The concern with which Canadian regulators view utilities under their jurisdiction that are speculating in land is not new. In *Re Consumers' Gas Co.* (1976), E.B.R.O. 341-I, the Ontario Energy Board considered how to deal with a real estate profit on land which was disposed of at an after-tax profit of over $2 million. The Board stated:

> The Station "B" property was not purchased by Consumers' for land speculation but was acquired for utility purposes. This investment, while non-depreciable, was subject to interest charges and risk paid for through revenues and, until the gas manufacturing plant became obsolete, disposal of the land was not a feasible option. <u>If, in such circumstances, the Board were to permit real estate profit to accrue to the shareholders only, it would tend to encourage real estate speculation with utility capital</u>. In the Board's opinion, the shareholders and the ratepayers should share the benefits of such capital gains. [Emphasis added; para. 326.]

116 Some U.S. regulators also consider it good regulatory policy to allocate part or all of the profit to offset costs in the rate base. In *Boston Gas Co., Re*, 49 P.U.R. 4th 1 (U.S. Mass. D.P.U. 1982), the regulator allocated a gain on the sale of land to ratepayers, stating:

> The company and its shareholders have received a return on the use of these parcels while they have been included in rate base, and are not entitled to any additional return as a result of their sale. <u>To hold otherwise would be to find that a regulated utility company may speculate in nondepreciable utility property and, despite earning a reasonable rate of return from its customers on that property, may also accumulate a windfall through its sale</u>. We find this to be an uncharacteristic risk/reward situation for a regulated utility to be in with respect to its plant in service. [Emphasis added.]

117 Canadian regulators other than the Board are also concerned with the prospect that decisions of utilities in their regulated business may be skewed under the undue influence of prospective profits on land sales. In *Re Consumers' Gas Co.* (1991), E.B.R.O. 465, the Ontario Energy Board determined that a $1.9 million gain on sale of land should be divided equally between shareholders and ratepayers. It held that

> ...the allocation of 100 percent of the profit from land sales to either the shareholders or the ratepayers might diminish the recognition of the valid concerns of the excluded party. For example, the timing and intensity of land purchase and sales negotiations could be skewed to favour or disregard the ultimate beneficiary (para. 3.3.8).

118 The Board's principle of dividing the gain between investors and ratepayers is consistent, as well, with *Re Natural Resource Gas Ltd.*, RP-2002-0147; EB-2002-0446, in which the Ontario Energy Board addressed the allocation of a profit on the sale of land and buildings and again stated:

> The Board finds that it is reasonable in the circumstances that the capital gains be shared equally between the Company and its customers. In making this finding the Board has considered the non-recurring nature of this transaction (para. 45).

119 The wide variety of regulatory treatment of such gains was noted by Kerans J.A. in *Transalta (1986)*, at pp. 175-76, including *Boston Gas Co., Re* mentioned earlier. In *Transalta (1986)*, the Board characterized TransAlta's gain on the disposal of land and buildings included in its Edmonton "franchise" as "revenue" within the meaning of the *Hydro and Electric Energy Act*, R.S.A. 1980, c. H-13. (The case therefore did not deal with the power to impose conditions "the Board considers necessary in the public interest".) Kerans J.A. said (at p. 176):

> I do not agree with the Board's decision for reasons later expressed, but it would be fatuous to deny that its interpretation [of the word "revenue"] is one which the word can reasonably bear.

Kerans J.A. went on to find that in that case "[t]he compensation was, for all practical purposes, compensation for loss of franchise" (p. 180) and on that basis the gain in these "unique circumstances" (p. 179) could not, as a matter of law, be characterized as revenue, i.e. applying a correctness standard. The range of regulatory practice on the "gains on sale" issue was similarly noted by Goldie J.A. in *Yukon Energy Corp. v. Yukon (Utilities Board)* (1996), 74 B.C.A.C. 58, 121 W.A.C. 58 (Y.T. C.A.), at para. 85.

120 A survey of recent regulatory experience in the United States reveals the wide variety of treatment in that country of gains on the sale of undepreciated land. The range includes proponents of ATCO's preferred allocation as well as proponents of the solution adopted by the Board in this case:

> Some jurisdictions have concluded that as a matter of equity, shareholders alone should benefit from any gain realized on appreciated real estate, because ratepayers generally pay only for taxes on the land and do not contribute to the cost of acquiring the property and pay no depreciation expenses. Under this analysis, ratepayers assume no risk for losses and acquire no legal or equitable interest in the property, but rather pay only for the use of the land in utility service.
>
> Other jurisdictions claim that ratepayers should retain some of the benefits associated with the sale of property dedicated to utility service. Those jurisdictions that have adopted an equitable sharing approach agree that a review of regulatory and judicial decisions on the issue does not reveal any general principle that requires the allocation of benefits solely to shareholders; rather, the cases show only a general prohibition against sharing benefits on the sale property that has never been reflected in utility rates.
>
> (P. S. Cross, "Rate Treatment of Gain on Sale of Land: Ratepayer Indifference, A New Standard?" (1990), *Public Utilities Fortnightly* 44, at p. 44)

Regulatory opinion in the United States favourable to the solution adopted here by the Board is illustrated by *Arizona Public Service Co., Re*, 91 P.U.R. 4th 337, 1988 WL 391394 (U.S. Ariz. C.C. 1988):

> To the extent any general principles can be gleaned from the decisions in other jurisdictions they are: (1) the utility's stockholders are not automatically entitled to the gains from all sales of utility property; and (2) ratepayers are not entitled to all or any part of a gain from the sale of property which has never been reflected in the utility's rates.

121 Assets purchased with capital reflected in the rate base come and go, but the utility itself endures. What was done by the Board in this case is quite consistent with the "enduring enterprise" theory espoused, for example, in *Southern California Water Co., Re*, 43 CPUC (2d) 596, 1992 WL 584058 (U.S. Cal. P.U.C. 1992). In that case, Southern California Water had asked for approval to sell an old headquarters building and the issue was how to allocate its profits on the sale. The Commission held:

> Working from the principle of the "enduring enterprise", the gain-on-sale from this transaction should remain within the utility's operations rather than being distributed in the short run directly to either ratepayers or shareholders. The "enduring enterprise" principle, is neither novel nor radical. It was clearly articulated by the Commission in its seminal 1989 policy decision on the issue of gain-on-sale, D. 89-07-016, 32 Cal. P.U.C. 2d 233 (Redding). Simply stated, to the extent that a utility realizes a gain-on-sale from the liquidation of an asset and replaces it with another asset or obligation while at the same time its responsibility to serve its customers is neither relieved nor reduced, then any gain-on-sale should remain within the utility's operation.

122 In my view, neither the Alberta statutes nor regulatory practice in Alberta and elsewhere dictates the answer to the problems confronting the Board. It would have been open to the Board to allow ATCO's application for the entire profit. But the solution it adopted was quite within its statutory authority and does not call for judicial intervention.

F. ATCO's Arguments

123 Most of ATCO's principal submissions have already been touched on but I will repeat them here for convenience. ATCO does not really dispute the Board's ability to impose conditions on the sale of land. Rather, ATCO says that what the Board did here violates a number of basic legal protections and principles. It asks the Court to clip the Board's wings.

124 Firstly, ATCO says that customers do not acquire any proprietary right in the company's assets. ATCO, rather than its customers, originally purchased the property, held title to it, and therefore was entitled to any gain on its sale. An allocation of profit to the customers would amount to a confiscation of the corporation's property.

125 Secondly, ATCO says its retention of 100% of the gain has nothing to do with the so-called "regulatory compact". The gas customers paid what the Board regarded over the years as a fair price for safe and reliable service. That is what the ratepayers got and that is all they were entitled to. The Board's allocation of part of the profit to the ratepayers amounts to impermissible "retroactive" rate setting.

126 Thirdly, utilities are not entitled to include in the rate base an amount for *depreciation* on land and ratepayers have therefore not repaid ATCO any part of ATCO's original cost, let alone the present value. The treatment accorded gain on sales of depreciated property therefore does not apply.

127 Fourthly, ATCO complains that the Board's solution is asymmetrical. Ratepayers are given part of the benefit of an increase in land values without, in a falling market, bearing any part of the burden of losses on the disposition of land.

128 In my view, these are all arguments that should be (and were) properly directed to the Board. There are indeed precedents in the regulatory field for what ATCO proposes, just as there are precedents for what the ratepayers proposed. It was for the Board to decide what conditions in these particular circumstances were necessary in the public interest. The Board's solution in this case is well within the range of reasonable options, as I will endeavour to demonstrate.

1. The Confiscation Issue

129 In its factum, ATCO says that "[t]he property belonged to the owner of the utility and the Board's proposed distribution cannot be characterized otherwise than as being confiscatory" (respondent's factum, para. 6). ATCO's argument overlooks the

obvious difference between investment in an unregulated business and investment in a regulated utility where the regulator sets the return on investment, not the market place. In *Southern California Gas Co., Re*, 38 CPUC (2d) 166, 118 P.U.R. 4th 81, 1990 WL 488654 (U.S. Cal. P.U.C. 1990) ("*SoCalGas*"), the regulator pointed out:

> In the non-utility private sector, investors are not guaranteed to earn a fair return on such sunk investment. Although shareholders and bondholders provide the initial capital investment, the ratepayers pay the taxes, maintenance, and other costs of carrying utility property in rate base over the years, and thus insulate utility investors from the risk of having to pay those costs. Ratepayers also pay the utility a fair return on property (including land) while it is in rate base, compensate the utility for the diminishment of the value of its depreciable property over time through depreciation accounting, and bear the risk that they must pay depreciation and a return on prematurely retired rate base property.

(It is understood, of course, that the Board does not appropriate the actual proceeds of sale. What happens is that an amount *equivalent* to two-thirds of the profit is included in the calculation of ATCO's current cost base for rate making purposes. In that way, there is a notional distribution of the benefit of the gain amongst the competing stakeholders.)

130 ATCO's argument is frequently asserted in the United States under the flag of constitutional protection for "property". Constitutional protection has not however prevented allocation of all or part of such gains to the U.S. ratepayers. One of the leading U.S. authorities is *Democratic Central Committee of the District of Columbia v. Washington Metropolitan Area Transit Commission*, 485 F.2d 786 (U.S. C.A. D.C. 1973). In that case, the assets at issue were parcels of real estate which had been employed in mass transit operations but which were no longer needed when the transit system converted to buses. The regulator awarded the profit on the appreciated land values to the shareholders but the Court of Appeals reversed the decision, using language directly applicable to ATCO's "confiscation" argument:

> We perceive no impediment, constitutional or otherwise, to recognition of a ratemaking principle enabling ratepayers to benefit from appreciations in value of utility properties accruing while in service. We believe the doctrinal consideration upon which pronouncements to the contrary have primarily rested has lost all present-day vitality. Underlying these pronouncements is a basic legal and economic thesis _ sometimes articulated, sometimes implicit _ that utility assets, though dedicated to the public service, remain exclusively the property of the utility's investors, and that growth in value is an inseparable and inviolate incident of that property interest. The precept of private ownership historically pervading our jurisprudence led naturally to such a thesis, and early decisions in the ratemaking field lent some support to it; if still viable, it strengthens the investor's claim. We think, however, after careful exploration, that the foundations for that approach, and the conclusion it seemed to indicate, have long since eroded away (p. 800).

The court's reference to "pronouncements" which have "lost all present-day vitality" likely includes *Board of Public Utility Commissioners v. New York Telephone Co.*, 271 U.S. 23 (U.S.S.C. 1926), a decision relied upon in this case by ATCO. In that case, the Supreme Court of the United States said (at p. 31):

> Customers pay for service, not for the property used to render it. Their payments are not contributions to depreciation or other operating expenses or to capital of the company. By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company. Property paid for out of moneys received for service belongs to the company just as does that purchased out of proceeds of its bonds and stock.

In that case, the regulator belatedly concluded that the level of depreciation allowed the New York Telephone Company had been excessive in past years and sought to remedy the situation in the current year by retroactively adjusting the cost base. The court held that the regulator had no power to re-open past rates. The financial fruits of the regulator's errors in past years now belonged to the company. That is not this case. No one contends that the Board's prior rates, based on ATCO's original investment, were wrong. In 2001, when the matter came before the Board, the Board had jurisdiction to approve or not approve the proposed sale. It was not a done deal. The receipt of any profit by ATCO was prospective only. As explained in *Arizona Public Service Co., Re*:

> In New York Telephone, the issue presented was whether a state regulatory commission could use excessive depreciation accruals from prior years to reduce rates for future service and thereby set rates which did not yield a just return .... the Court simply reiterated and provided the reasons for a ratemaking truism: rates must be designed to produce enough revenue to pay current [reasonable] operating expenses and provide a fair return to the utility's investors. If it turns out that, for whatever reason, existing rates have produced too much or too little income, the past is past. <u>Rates are raised or lowered to reflect current conditions; they are not designed to pay back past excessive profits or recoup past operating losses</u>. In contrast, the issue in this proceeding is whether for ratemaking purposes a utility's test year income from sales of utility service can include its income from sales of utility property. The United States Supreme Court's decision in New York Telephone does not address that issue. [Emphasis added.]

131 More recently, the allocation of gain on sale was addressed by the California Public Utilities Commission in *SoCalGas*. In that case, as here, the utility (SoCalGas) wished to sell land and buildings located (in that case) in downtown Los Angeles. The Commission apportioned the gain on sale between the shareholders and the ratepayers, concluding that:

> We believe that the issue of who owns the utility property providing utility service has become a red herring in this case, and that ownership alone does not determine who is entitled to the gain on the sale of the property providing utility service when it is removed from rate base and sold.

132 ATCO argues in its factum that ratepayers "do not acquire any interest, legal or equitable, in the property used to provide the service or in the funds of the owner of the utility" (para. 2). In *SoCalGas*, the regulator disposed of this point as follows:

> No one seriously argues that ratepayers acquire title to the physical property assets used to provide utility service; DRA [Division of Ratepayer Advocates] argues that the gain on sale should reduce future revenue requirements not because ratepayers own the property, but rather because they paid the costs and faced the risks associated with that property while it was in rate base providing public service.

This "risk" theory applies in Alberta as well. Over the last 80 years, there have been wild swings in Alberta real estate, yet through it all, in bad times and good, the ratepayers have guaranteed ATCO a just and equitable return on its investment in *this* land and *these* buildings.

133 The notion that the division of risk justifies a division of the net gain was also adopted by the regulator in *SoCalGas*:

> Although the shareholders and bondholders provided the initial capital investment, the ratepayers paid the taxes, maintenance, and other costs of carrying the land and buildings in rate base over the years, and paid the utility a fair return on its unamortized investment in the land and buildings while they were in rate base.

In other words, even in the United States, where property rights are constitutionally protected, ATCO's "confiscation" point is rejected as an oversimplification.

134 My point is not that the Board's allocation in this case is necessarily correct in all circumstances. Other regulators have determined that the public interest requires a different allocation. The Board proceeds on a "case-by-case" basis. My point simply is that the Board's response in this case cannot be considered "confiscatory" in any proper use of the term, and is well within the range of what are regarded in comparable jurisdictions as appropriate regulatory responses to the allocation of the gain on sale of land whose original investment has been included by the utility itself in its rate base. The Board's decision is protected by a deferential standard of review and in my view it should not have been set aside.

2. The Regulatory Compact

135 The Board referred in its decision to the "regulatory compact" which is a loose expression suggesting that in exchange for a statutory monopoly and receipt of revenue on a cost plus basis, the utility accepts limitations on its rate of return and its freedom to do as it wishes with property whose cost is reflected in its rate base. This was expressed in the *Washington Metropolitan Area Transit* case by the U.S. Court of Appeals as follows (at p. 806):

> The ratemaking process involves fundamentally "a balancing of the investor and the consumer interests." The investor's interest lies in the integrity of his investment and a fair opportunity for a reasonable return thereon. The consumer's interest lies in governmental protection against unreasonable charges for the monopolistic service to which he subscribes. In terms of property value appreciations, the balance is best struck at the point at which the interests of both groups receive maximum accommodation.

136 ATCO considers that the Board's allocation of profit violated the regulatory compact not only because it is confiscatory but because it amounts to "retroactive rate making". In *Northwestern Utilities Ltd. v. Edmonton (City)* (1978), [1979] 1 S.C.R. 684 (S.C.C.), Estey J. stated, at p. 691:

> It is clear from many provisions of *The Gas Utilities Act* that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods.

137 As stated earlier, the Board in this case was addressing a prospective receipt and allocated two thirds of it to a prospective (not retroactive) rate making exercise. This is consistent with regulatory practice, as is illustrated by *New York Water Service Co. v. Public Service Commission*, 208 N.Y.S.2d 857 (U.S. S.C. Ct. App. 1962). In that case, a utility commission ruled that gains on the sale of real estate should be taken into account to reduce rates annually over the following period of 17 years (p. 864):

> If land is sold at a profit, it is required that the profit be added to, i.e., "credited to", the depreciation reserve, so that there is a corresponding reduction of the rate base and resulting return.

The regulator's order was upheld by the New York State Supreme Court (Appellate Division).

138 More recently, in *Compliance with the Energy Policy Act of 1992, Re*, 62 CPUC (2d) 517, WL 768628 (U.S. Cal. P.U.C. 1995), the regulator commented:

> ...we found it appropriate to allocate the principal amount of the gain to offset future costs of headquarters facilities, because ratepayers had borne the burden of risks and expenses while the property was in ratebase. At the same time, we found that it was equitable to allocate a portion of the benefits from the gain-on-sale to shareholders in order to provide a reasonable incentive to the utility to maximize the proceeds from selling such property and compensate shareholders for any risks borne in connection with holding the former property.

139 The emphasis in all these cases is on balancing the interests of the shareholders and the ratepayers. This is perfectly consistent with the "regulatory compact" approach reflected in the Board doing what it did in this case.

3. Land as a Non-Depreciable Asset

140 The Alberta Court of Appeal drew a distinction between gains on sale of land, whose original cost is not depreciated (and thus is not repaid in increments through the rate base) and depreciated property such as buildings where the rate base does include a measure of capital repayment and which in that sense the ratepayers have "paid for". The Alberta Court of Appeal held that the Board was correct to credit the rate base with an amount equivalent to the depreciation paid in respect of the buildings (this is the subject matter of ATCO's cross-appeal). Thus in this case, the land was still carried on ATCO's books at its original price of $83,720 whereas the original $596,591 cost of the buildings had been depreciated through the rates charged customers to a net book value of $141,525.

141 Regulatory practice shows that many (not all) regulators also do not accept the distinction (for this purpose) between depreciable and non-depreciable assets. In *Boston Gas Co., Re* for example (cited in *Transalta (1986)*, at p. 176), the regulator held:

> ...the company's ratepayers have been paying a return on this land as well as all other costs associated with its use. The fact that land is a nondepreciable asset because its useful value is not ordinarily diminished through use is, we find, irrelevant to the question of who is entitled to the proceeds on the sales of this land.

142 In *SoCalGas*, as well, the Commission declined to make a distinction between the gain on sale of depreciable, as compared to non-depreciable, property, stating "We see little reason why land sales should be treated differently." The decision continued:

> In short, whether an asset is depreciated for ratemaking purposes or not, ratepayers commit to paying a return on its book value for as long as it is used and useful. Depreciation simply recognizes the fact that certain assets are consumed over a period of utility service while others are not. <u>The basic relationship between the utility and its ratepayers is the same for depreciable and non-depreciable assets</u>. [Emphasis added.]

143 In *California Water Service Co., Re*, 66 CPUC (2d) 100, 1996 WL 293205 (U.S. Cal. P.U.C. 1996), the regulator commented that:

> Our decisions generally find no reason to treat gain on the sale of nondepreciable property, such as bare land, different[ly] than gains on the sale of depreciable rate base assets and land in PHFU [plant held for future use].

144 Again, my point is not that the regulator *must* reject any distinction between depreciable and non-depreciable property. Simply, my point is that the distinction does not have the controlling weight as contended by ATCO. In Alberta, it is up to the Board to determine what allocations are necessary in the public interest as conditions of the approval of sale. ATCO's attempt to limit the Board's discretion by reference to various doctrine is not consistent with the broad statutory language used by the Alberta legislature and should be rejected.

4. Lack of Reciprocity

145 ATCO argues that the customers should not profit from a rising market because if the land loses value it is ATCO, and not the ratepayers, that will absorb the loss. However, the material put before the Court suggests that the Board takes into account both gains *and* losses. In the following decisions the Board stated, repeated, and repeated again its "general rule" that

> ...the Board considers that any profit <u>or loss</u> (being the difference between the net book value of the assets and the sale price of those assets) resulting from the disposal of utility assets <u>should accrue to the customers of the utility</u> and not to the owner of the utility. [Emphasis added.]

(See *TransAlta Utilities Corp.* (1984), Alta. P.U.B. Decision No. E84116, at p. 17; *TransAlta Utilities Corp.* (1984), Alta. P.U.B. Decision No. E84115, at p. 12; *Re Gas Utilities Act and Public Utilities Board Act*, (1984), Alta. P.U.B. Decision No. E84113, at p. 23.)

146 In *Alberta Government Telephones*, the Board reviewed a number of regulatory approaches (including *Boston Gas Co., Re*, previously mentioned) with respect to gains on sale and concluded with respect to its own practice, at p. 12:

> The Board is aware that it has not applied any consistent formula or rule which would automatically determine the accounting procedure to be followed in the treatment of gains or losses on the disposition of utility assets. The reason for this is that the Board's determination of what is fair and reasonable rests on the merits or facts of each case.

147 ATCO's contention that it alone is burdened with the risk on land that *declines* in value overlooks the fact that in a falling market, the utility continues to be entitled to a rate of return on its original investment even if the market value at the time is substantially less than its original investment. As pointed out in *SoCalGas*:

> If the land actually does depreciate in value below its original cost, then one view could be that the steady rate of return [the ratepayers] have paid for the land over time has actually overcompensated investors. Thus, there is symmetry of risk and reward associated with rate base land just as there is with regard to depreciable rate base property.

II. Conclusion

148 In summary, s. 15(3) of the AEUBA authorized the Board in dealing with ATCO's application to approve the sale of the subject land and buildings to "impose any additional conditions that the Board considers necessary in the public interest". In the exercise of that authority, and having regard to the Board's "general supervision over all gas utilities, and the owners of them" (GUA, s. 22(1)), the Board made an allocation of the net gain for the public policy reasons which it articulated in its decision. Perhaps not every regulator and not every jurisdiction would exercise the power in the same way, but the allocation of the gain on an asset ATCO sought to withdraw from the rate base was a decision the Board was mandated to make. It is not for the Court to substitute its own view of what is "necessary in the public interest".

III. Disposition

149 I would allow the appeal, set aside the decision of the Alberta Court of Appeal, and restore the decision of the Board, with costs to the City of Calgary both in this Court and in the court below. ATCO's cross-appeal should be dismissed with costs.

Appeal dismissed; cross-appeal allowed.

Pourvoi rejeté; pourvoi incident rejeté.

Appendix — APPENDIX

Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17

[Jurisdiction]

13 All matters that may be dealt with by the ERCB or the PUB under any enactment or as otherwise provided by law shall be dealt with by the Board and are within the exclusive jurisdiction of the Board.

[Powers of the Board]

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB and the PUB that are granted or provided for by any enactment or by law.

(2) In any case where the ERCB, the PUB or the Board may act in response to an application, complaint, direction, referral or request, the Board may act on its own initiative or motion.

(3) Without restricting subsection (1), the Board may do all or any of the following:

(a) make any order that the ERCB or the PUB may make under any enactment;

(b) with the approval of the Lieutenant Governor in Council, make any order that the ERCB may, with the approval of the Lieutenant Governor in Council, make under any enactment;

(c) with the approval of the Lieutenant Governor in Council, make any order that the PUB may, with the approval of the Lieutenant Governor in Council, make under any enactment;

(d) with respect to an order made by the Board, the ERCB or the PUB in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

(e) make an order granting the whole or part only of the relief applied for;

(f) where it appears to the Board to be just and proper, grant partial, further or other relief in addition to, or in substitution for, that applied for as fully and in all respects as if the application or matter had been for that partial, further or other relief.

[Appeals]

26(1) Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.

(2) Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made

(a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or

(b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

[Exclusion of prerogative writs]

27 Subject to section 26, every action, order, ruling or decision of the Board or the person exercising the powers or performing the duties of the Board is final and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court.

Gas Utilities Act, R.S.A. 2000, c. G-5

[Supervision]

22(1) The Board shall exercise a general supervision over all gas utilities, and the owners of them, and may make any orders regarding equipment, appliances, extensions of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

(2) The Board shall conduct all inquiries necessary for the obtaining of complete information as to the manner in which owners of gas utilities comply with the law, or as to any other matter or thing within the jurisdiction of the Board under this Act.

[Investigation of gas utility]

24(1) The Board, on its own initiative or on the application of a person having an interest, may investigate any matter concerning a gas utility.

[Designated gas utilities]

26(1) The Lieutenant Governor in Council may by regulation designate those owners of gas utilities to which this section and section 27 apply.

(2) No owner of a gas utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or

(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them,

unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,

(ii) a right, franchise or privilege in excess of the amount actually paid to the Government or a municipality as the consideration for it, exclusive of any tax or annual charge, or

(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of it or them,

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

[Prohibited share transactions]

27(1) Unless authorized to do so by an order of the Board, the owner of a gas utility designated under section 26(1) shall not sell or make or permit to be made on its books any transfer of any share or shares of its capital stock to a corporation, however incorporated, if the sale or transfer, by itself or in connection with previous sales or transfers, would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the gas utility.

[Powers of Board]

36 The Board, on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls or charges or schedules of them, as well as commutation and other special rates, which shall be imposed, observed and followed afterwards by the owner of the gas utility,

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a gas utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Board,

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed, observed and followed thereafter by the owner of the gas utility,

(d) require an owner of a gas utility to establish, construct, maintain and operate, but in compliance with this and any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Board the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the gas utility reasonably warrants the original expenditure required in making and operating the extension, and

(e) require an owner of a gas utility to supply and deliver gas to the persons, for the purposes, at the rates, prices and charges and on the terms and conditions that the Board directs, fixes or imposes.

[Rate base]

37(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

(2) In determining a rate base under this section, the Board shall give due consideration

(a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and

(b) to necessary working capital.

(3) In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Board shall give due consideration to all facts that in its opinion are relevant.

[Excess revenues or losses]

40 In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of that period,

(b) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines is just and reasonable,

(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines has been due to undue delay in the hearing and determining of the matter, and

(d) the Board shall by order approve

(i) the method by which, and

(ii) the period, including any subsequent fiscal period, during which,

any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.

[General powers of Board]

59 For the purposes of this Act, the Board has the same powers in respect of the plant, premises, equipment, service and organization for the production, distribution and sale of gas in Alberta, and in respect of the business of an owner of a gas utility and in respect of an owner of a gas utility, that are by the *Public Utilities Board Act* conferred on the Board in the case of a public utility under that Act.

Public Utilities Board Act, R.S.A. 2000, c. P-45

[Jurisdiction and powers]

36(1) The Board has all the necessary jurisdiction and power

(a) to deal with public utilities and the owners of them as provided in this Act;

(b) to deal with public utilities and related matters as they concern suburban areas adjacent to a city, as provided in this Act.

(2) In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute or pursuant to statutory authority.

(3) The Board has, and is deemed at all times to have had, jurisdiction to fix and settle, on application, the price and terms of purchase by a council of a municipality pursuant to section 47 of the *Municipal Government Act*

(a) before the exercise by the council under that provision of its right to purchase and without binding the council to purchase, or

(b) when an application is made under that provision for the Board's consent to the purchase, before hearing or determining the application for its consent.

[General power]

37 In matters within its jurisdiction the Board may order and require any person or local authority to do forthwith or within or at a specified time and in any manner prescribed by the Board, so far as it is not inconsistent with this Act or any other Act conferring jurisdiction, any act, matter or thing that the person or local authority is or may be required to do under this Act or under any other general or special Act, and may forbid the doing or continuing of any act, matter or thing that is in contravention of any such Act or of any regulation, rule, order or direction of the Board.

[Investigation of utilities and rates]

80 When it is made to appear to the Board, on the application of an owner of a public utility or of a municipality or person having an interest, present or contingent, in the matter in respect of which the application is made, that there is reason to believe that the tolls demanded by an owner of a public utility exceed what is just and reasonable, having regard to the nature and quality of the service rendered or of the commodity supplied, the Board

(a) may proceed to hold any investigation that it thinks fit into all matters relating to the nature and quality of the service or the commodity in question, or to the performance of the service and the tolls or charges demanded for it,

(b) may make any order respecting the improvement of the service or commodity and as to the tolls or charges demanded, that seems to it to be just and reasonable, and

(c) may disallow or change, as it thinks reasonable, any such tolls or charges that, in its opinion, are excessive, unjust or unreasonable or unjustly discriminate between different persons or different municipalities, but subject however to any provisions of any contract existing between the owner of the public utility and a municipality at the time the application is made that the Board considers fair and reasonable.

[Supervision by Board]

85(1) The Board shall exercise a general supervision over all public utilities, and the owners of them, and may make any orders regarding extension of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

[Investigation of public utility]

87(1) The Board may, on its own initiative, or on the application of a person having an interest, investigate any matter concerning a public utility.

(2) When in the opinion of the Board it is necessary to investigate a public utility or the affairs of its owner, the Board shall be given access to and may use any books, documents or records with respect to the public utility and in the possession of any owner of the public utility or municipality or under the control of a board, commission or department of the Government.

(3) A person who directly or indirectly controls the business of an owner of a public utility within Alberta and any company controlled by that person shall give the Board or its agent access to any of the books, documents and records that relate to the business of the owner or shall furnish any information in respect of it required by the Board.

[Fixing of rates]

89 The Board, either on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls or charges, or schedules of them, as well as commutation, mileage or kilometre rate and other special rates, which shall be imposed, observed and followed subsequently by the owner of the public utility;

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a public utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Board;

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed, observed and followed subsequently by the owner of the public utility;

(d) repealed;

(e) require an owner of a public utility to establish, construct, maintain and operate, but in compliance with other provisions of this or any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Board the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the public utility reasonably warrants the original expenditure required in making and operating the extension.

[Determining rate base]

90(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed subsequently by an owner of a public utility, the Board shall determine a rate base for the property of the owner of a public utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

(2) In determining a rate base under this section, the Board shall give due consideration

(a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the public utility, less depreciation, amortization or depletion in respect of each, and

(b) to necessary working capital.

(3) In fixing the fair return that an owner of a public utility is entitled to earn on the rate base, the Board shall give due consideration to all those facts that, in the Board's opinion, are relevant.

[Revenue and costs considered]

91(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed by an owner of a public utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of such a period,

(b) the Board shall consider the effect of the *Small Power Research and Development Act* on the revenues and costs of the owner with respect to the generation, transmission and distribution of electric energy,

(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Board determines is just and reasonable,

(d) the Board may give effect to such part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Board determines has been due to undue delay in the hearing and determining of the matter, and

(e) the Board shall by order approve the method by which, and the period (including any subsequent fiscal period) during which, any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (c) or (d), is to be used or dealt with.

[Designated public utilities]

101(1) The Lieutenant Governor in Council may by regulation designate those owners of public utilities to which this section and section 102 apply.

(2) No owner of a public utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or

(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them, unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,

(ii) a right, franchise or privilege in excess of the amount actually paid to the Government or a municipality as the consideration for it, exclusive of any tax or annual charge, or

(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of them,

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a public utility designated under subsection (1) in the ordinary course of the owner's business.

[Prohibited share transaction]

102(1) Unless authorized to do so by an order of the Board, the owner of a public utility designated under section 101(1) shall not sell or make or permit to be made on its books a transfer of any share of its capital stock to a corporation, however incorporated, if the sale or transfer, in itself or in connection with previous sales or transfers, would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the public utility.

Interpretation Act, R.S.A. 2000, c. I-8

[Enactments remedial]

10 An enactment shall be construed as being remedial, and shall be given the fair, large and liberal construction and interpretation that best ensures the attainment of its objects.

Footnotes

* A corrigendum issued by the court on April 24, 2006 has been incorporated herein.

2015 SCC 23, 2015 CSC 23
Supreme Court of Canada

White Burgess Langille Inman v. Abbott and Haliburton Co.

2015 CarswellNS 313, 2015 CarswellNS 314, 2015 SCC 23, 2015 CSC 23, [2015] 2 S.C.R. 182, [2015] S.C.J. No. 23, 1135 A.P.R. 1, 18 C.R. (7th) 308, 251 A.C.W.S. (3d) 610, 360 N.S.R. (2d) 1, 383 D.L.R. (4th) 429, 470 N.R. 324, 67 C.P.C. (7th) 73, J.E. 2015-767

White Burgess Langille Inman, carrying on business as WBLI Chartered Accountants and R. Brian Burgess (Appellants) and Abbott and Haliburton Company Limited, A.W. Allen & Son Limited, Berwick Building Supplies Limited, Bishop's Falls Building Supplies Limited, Arthur Boudreau & Fils Ltée, Brennan Contractors & Supplies Ltd., F. J. Brideau & Fils Limitée, Cabot Building Supplies Company (1988) Limited, Robert Churchill Building Supplies Limited, CDL Holdings Limited, formerly Chester Dawe Limited, Fraser Supplies (1980) Ltd., R. D. Gillis Building Supplies Limited, Yvon Godin Ltd., Truro Wood Industries Limited/Home Care Properties Limited, Hann's Hardware and Sporting Goods Limited, Harbour Breton Building Supplies Limited, Hillier's Trades Limited, Hubcraft Building Supplies Limited, Lumbermart Limited, Maple Leaf Farm Supplies Limited, S.W. Mifflin Ltd., Nauss Brothers Limited, O'Leary Farmers' Co-operative Ass'n. Ltd., Pellerin Building Supplies Inc., Pleasant Supplies Incorporated, J. I. Pritchett & Sons Limited, Centre Multi-Décor de Richibucto Ltée, U. J. Robichaud & Sons Woodworkers Limited, Quincaillerie Saint-Louis Ltée, R & J Swinamer's Supplies Limited, 508686 N.B. INC. operating as T.N.T. Insulation and Building Supplies, Taylor Lumber and Building Supplies Limited, Two by Four Lumber Sales Ltd., Walbourne Enterprises Ltd., Western Bay Hardware Limited, White's Construction Limited, D. J. Williams and Sons Limited and Woodland Building Supplies Limited (Respondents) and Attorney General of Canada and Criminal Lawyers' Association (Ontario) (Interveners)

McLachlin C.J.C., Abella, Rothstein, Cromwell, Moldaver, Wagner, Gascon JJ.

Heard: October 7, 2014
Judgment: April 30, 2015
Docket: 35492

Proceedings: affirming *Abbott and Haliburton Co. v. White Burgess Langille Inman* (2013), (sub nom. *Abbott and Haliburton Co. v. WBLI Chartered Accountants)* 330 N.S.R. (2d) 301, 1046 A.P.R. 301, 361 D.L.R. (4th) 659, 2013 CarswellNS 360, [2013] N.S.J. No. 259, 2013 NSCA 66, 36 C.P.C. (7th) 22, Beveridge J.A., MacDonald C.J.N.S., Oland J.A. (N.S. C.A.); reversing in part *Abbott and Haliburton Co. v. White Burgess Langille Inman* (2012), 26 C.P.C. (7th) 280, (sub nom. *Abbott & Haliburton Co. Ltd. v. WBLI Chartered Accountants)* 317 N.S.R. (2d) 283, 1003 A.P.R. 283, 2012 CarswellNS 376, 2012 NSSC 210, Arthur W.D. Pickup J. (N.S. S.C.)

Counsel: Alan D'Silva, James Wilson, Aaron Kreaden, for Appellants
Jon Laxer, Brian F. P. Murphy, for Respondents
Michael H. Morris, for Intervener, Attorney General of Canada
Matthew Gourlay, for Intervener, Criminal Lawyers' Association

Comment

White Burgess Langille Inman v. Abbott and Haliburton Co. comprehensively restates the law on admissibility of expert evidence in civil and criminal cases. A unanimous Supreme Court adopts the key feature of the judgment of Doherty J. in *R. v. Abbey*, 2009 ONCA 624, 68 C.R. (6th) 201 (Ont. C.A.) by holding that the admissibility analysis has two stages — a set of threshold preconditions to admissibility and a discretionary gatekeeper stage (see para. 22, adopting *Abbey*). The Court also resolves a longstanding question in the Canadian case law by holding that defects in an expert witness's independence and impartiality can go to admissibility and not only to weight (para. 45). In fact, on examination, the Court's analysis indicates that problems of independence and impartiality may properly be considered at three separate stages in the analysis of expert evidence. First, the question whether proposed expert witnesses are able and willing to comply with their duties to the court can be addressed at the threshold stage of the admissibility analysis under the "qualified expert" requirement (para. 53). Second, even when the expert is qualified, questions about independence and impartiality can be taken into account at the gatekeeper stage (para. 54). But this too is a question of admissibility to be considered by the trier of law. What may be obscured by the Court's emphasis on admissibility is the third stage when these concerns enter the analysis: independence and impartiality can also be considered by the trier of fact where the evidence is admitted (para. 45).

Given that *White Burgess Langille Inman* will become the starting point for argument on the admissibility of expert evidence, it is somewhat disappointing that the Court did not provide an easily accessible summary of the admissibility analysis. Instead, one must carefully read through the judgment to piece together the features of the admissibility framework. One might attempt to summarize that framework as follows:

Expert evidence is admissible when

1) it meets the threshold requirements of admissibility, which are that

a. the evidence must be logically relevant;

b. the evidence must be necessary to assist the trier of fact;

c. there must be no other exclusionary rule;

d. the expert must be properly qualified, which includes the requirement that the expert be willing and able to fulfil the duty to the court to provide evidence that is

i. impartial,

ii. independent and

iii. unbiased; and

e. for opinions based on novel or contested science or science used for a novel purpose, the underlying science must be reliable for that purpose;

and

2) it passes scrutiny at the gatekeeper stage, and the trial judge determines that the benefits of admitting the evidence outweigh its potential risks, considering such factors as

a. relevance,

b. necessity,

c. reliability, and

d. absence of bias (see para. 54).

Certain features of this framework will require clarification and amplification in the future. For example, the Court's reference to reliability as a threshold requirement "in the case of an opinion based on novel or contested science or science used for a novel purpose" (para. 23) leaves open the status of the reliability tests for non-scientific evidence that were extensively discussed in *Abbey*. While some questions remain, the framework outlined in *White Burgess Langille Inman* renews and clarifies the structure of the admissibility analysis for expert evidence.

Lisa Dufraimont

Faculty of Law, Queen's University

Cromwell J. **(McLachlin C.J.C. and Abella, Rothstein, Moldaver, Wagner and Gascon JJ. concurring):**

I. Introduction and Issues

1 Expert opinion evidence can be a key element in the search for truth, but it may also pose special dangers. To guard against them, the Court over the last 20 years or so has progressively tightened the rules of admissibility and enhanced the trial judge's gatekeeping role. These developments seek to ensure that expert opinion evidence meets certain basic standards before it is admitted. The question on this appeal is whether one of these basic standards for admissibility should relate to the proposed expert's independence and impartiality. In my view, it should.

2 Expert witnesses have a special duty to the court to provide fair, objective and non-partisan assistance. A proposed expert witness who is unable or unwilling to comply with this duty is not qualified to give expert opinion evidence and should not be permitted to do so. Less fundamental concerns about an expert's independence and impartiality should be taken into account in the broader, overall weighing of the costs and benefits of receiving the evidence.

3 Applying these principles, I agree with the conclusion reached by the majority of the Nova Scotia Court of Appeal and would therefore dismiss this appeal with costs.

II. Overview of the Facts and Judicial History

A. Facts and Proceedings

4 The appeal arises out of a professional negligence action by the respondents (who I will call the shareholders) against the appellants, the former auditors of their company (I will refer to them as the auditors). The shareholders started the action after they had retained a different accounting firm, the Kentville office of Grant Thornton LLP, to perform various accounting tasks and which in their view revealed problems with the auditors' previous work. The central allegation in the action is that the auditors' failure to apply generally accepted auditing and accounting standards while carrying out their functions caused financial loss to the shareholders. The main question in the action boils down to whether the auditors were negligent in the performance of their professional duties.

5 The auditors brought a motion for summary judgment in August of 2010, seeking to have the shareholders' action dismissed. In response, the shareholders retained Susan MacMillan, a forensic accounting partner at the Halifax office of Grant Thornton, to review all the relevant materials, including the documents filed in the action, and to prepare a report of her findings. Her affidavit set out her findings, including her opinion that the auditors had not complied with their professional obligations to the shareholders. The auditors applied to strike out Ms. MacMillan's affidavit on the grounds that she was not an impartial expert witness. They argued that the action comes down to a battle of opinion between two accounting firms — the auditors' and the expert witness's. Ms. MacMillan's firm could be exposed to liability if its approach was not accepted by the court and, as a partner, Ms. MacMillan could be personally liable. Her potential liability if her opinion were not accepted gives her a personal financial interest in the outcome of the litigations and this, in the auditors' submission, ought to disqualify her from testifying.

6 The proceedings since have been neither summary nor resulted in a judgment. Instead, the litigation has been focused on the expert evidence issue; the summary judgment application has not yet been heard on its merits.

B. Judgments Below

(1) Nova Scotia Supreme Court: 2012 NSSC 210, 317 N.S.R. (2d) 283 (N.S. S.C.) (Pickup J.)

7 Pickup J. essentially agreed with the auditors and struck out the MacMillan affidavit in its entirety: para. 106. He found that, in order to be admissible, an expert's evidence "must be, and be seen to be, independent and impartial": para. 99. Applying that test, he concluded that this was one of those "clearest of cases where the reliability of the expert ... does not meet the threshold requirements for admissibility": para. 101.

(2) Nova Scotia Court of Appeal: 2013 NSCA 66, 330 N.S.R. (2d) 301 (N.S. C.A.) (Beveridge J.A., Oland J.A. Concurring; MacDonald C.J.N.S., Dissenting)

8 The majority of the Court of Appeal concluded that the motions judge erred in excluding Ms. MacMillan's affidavit. Beveridge J.A. wrote that while the court has discretion to exclude expert evidence due to actual bias or partiality, the test adopted by the motions judge — that an expert "must be, and be seen to be, independent and impartial" — was wrong in law. He ought not to have ruled her evidence inadmissible and struck out her affidavit.

9 MacDonald C.J.N.S., dissenting, would have upheld the motions judge's decision because he had properly articulated and applied the relevant legal principles.

III. Analysis

A. Overview

10 In my view, expert witnesses have a duty to the court to give fair, objective and non-partisan opinion evidence. They must be aware of this duty and able and willing to carry it out. If they do not meet this threshold requirement, their evidence should not be admitted. Once this threshold is met, however, concerns about an expert witness's independence or impartiality should be considered as part of the overall weighing of the costs and benefits of admitting the evidence. This common law approach is, of course, subject to statutory and related provisions which may establish different rules of admissibility.

B. Expert Witness Independence and Impartiality

11 There have been long-standing concerns about whether expert witnesses hired by the parties are impartial in the sense that they are expressing their own unbiased professional opinion and whether they are independent in the sense that their opinion is the product of their own, independent conclusions based on their own knowledge and judgment: see, e.g., G. R. Anderson, *Expert Evidence* (3rd ed. 2014), at p. 509; S. N. Lederman, A. W. Bryant and M. K. Fuerst, *The Law of Evidence in Canada* (4th ed. 2014), at p. 783. As Sir George Jessel, M.R., put it in the 1870s, "[u]ndoubtedly there is a natural bias to do something serviceable for those who employ you and adequately remunerate you. It is very natural, and it is so effectual, that we constantly see persons, instead of considering themselves witnesses, rather consider themselves as the paid agents of the person who employs them": *Lord Abinger v. Ashton* (1873), L.R. 17 Eq. 358 (Eng. Rolls Ct.), at p. 374.

12 Recent experience has only exacerbated these concerns; we are now all too aware that an expert's lack of independence and impartiality can result in egregious miscarriages of justice: *R. v. D. (D.)*, 2000 SCC 43, [2000] 2 S.C.R. 275 (S.C.C.), at para. 52. As observed by Beveridge J.A. in this case, *The Commission on Proceedings Involving Guy Paul Morin: Report* (1998) authored by the Honourable Fred Kaufman and the *Inquiry into Pediatric Forensic Pathology in Ontario: Report* (2008) conducted by the Honourable Stephen T. Goudge provide two striking examples where "[s]eemingly solid and impartial, but flawed, forensic scientific opinion has played a prominent role in miscarriages of justice": para. 105. Other reports outline the critical need for impartial and independent expert evidence in civil litigation: *ibid.*, at para. 106; see the Right Honourable Lord Woolf, *Access to Justice: Final Report* (1996); the Honourable Coulter A. Osborne, *Civil Justice Reform Project: Summary of Findings & Recommendations* (2007).

13 To decide how our law of evidence should best respond to these concerns, we must confront several questions: Should concerns about potentially biased expert opinion go to admissibility or only to weight?; If to admissibility, should these concerns be addressed by a threshold requirement for admissibility, by a judicial discretion to exclude, or both?; At what point do these

concerns justify exclusion of the evidence?; And finally, how is our response to these concerns integrated into the existing legal framework governing the admissibility of expert opinion evidence? To answer these questions, we must first consider the existing legal framework governing admissibility, identify the duties that an expert witness has to the court and then turn to how those duties are best reflected in that legal framework.

C. The Legal Framework

(1) The Exclusionary Rule for Opinion Evidence

14 To the modern general rule that all relevant evidence is admissible there are many qualifications. One of them relates to opinion evidence, which is the subject of a complicated exclusionary rule. Witnesses are to testify as to the facts which they perceived, not as to the inferences — that is, the opinions — that they drew from them. As one great evidence scholar put it long ago, it is "for the jury to form opinions, and draw inferences and conclusions, and not for the witness": J. B. Thayer, *A Preliminary Treatise on Evidence at the Common Law* (1898; reprinted 1969), at p. 524; see also C. Tapper, *Cross and Tapper on Evidence* (12th ed. 2010), at p. 530. While various rationales have been offered for this exclusionary rule, the most convincing is probably that these ready-formed inferences are not helpful to the trier of fact and might even be misleading: see, e.g., *R. v. Graat*, [1982] 2 S.C.R. 819 (S.C.C.), at p. 836; *Halsbury's Laws of Canada: Evidence* (2014 Reissue), at para. HEV-137 "General rule against opinion evidence".

15 Not all opinion evidence is excluded, however. Most relevant for this case is the exception for expert opinion evidence on matters requiring specialized knowledge. As Prof. Tapper put it, "the law recognizes that, so far as matters calling for special knowledge or skill are concerned, judges and jurors are not necessarily equipped to draw true inferences from facts stated by witnesses. A witness is therefore allowed to state his opinion about such matters, provided he is expert in them": p. 530; see also *R. v. Abbey*, [1982] 2 S.C.R. 24 (S.C.C.), at p. 42.

(2) The Current Legal Framework for Expert Opinion Evidence

16 Since at least the mid-1990s, the Court has responded to a number of concerns about the impact on the litigation process of expert evidence of dubious value. The jurisprudence has clarified and tightened the threshold requirements for admissibility, added new requirements in order to assure reliability, particularly of novel scientific evidence, and emphasized the important role that judges should play as "gatekeepers" to screen out proposed evidence whose value does not justify the risk of confusion, time and expense that may result from its admission.

17 We can take as the starting point for these developments the Court's decision in *R. v. Mohan*, [1994] 2 S.C.R. 9 (S.C.C.). That case described the potential dangers of expert evidence and established a four-part threshold test for admissibility. The dangers are well known. One is that the trier of fact will inappropriately defer to the expert's opinion rather than carefully evaluate it. As Sopinka J. observed in *Mohan*:

> There is a danger that expert evidence will be misused and will distort the fact-finding process. Dressed up in scientific language which the jury does not easily understand and submitted through a witness of impressive antecedents, this evidence is apt to be accepted by the jury as being virtually infallible and as having more weight than it deserves. [p. 21]

(See also *D.D.*, at para. 53; *R. c. J. (J.-L.)*, 2000 SCC 51, [2000] 2 S.C.R. 600 (S.C.C.), at paras. 25-26; *R. v. Sekhon*, 2014 SCC 15, [2014] 1 S.C.R. 272 (S.C.C.), at para. 46.)

18 The point is to preserve trial by judge and jury, not devolve to trial by expert. There is a risk that the jury "will be unable to make an effective and critical assessment of the evidence": *R. v. Abbey*, 2009 ONCA 624, 97 O.R. (3d) 330 (Ont. C.A.), at para. 90, leave to appeal refused, [2010] 2 S.C.R. v (note) (S.C.C.). The trier of fact must be able to use its "informed judgment", not simply decide on the basis of an "act of faith" in the expert's opinion: *J. (J.-L.)*, at para. 56. The risk of "attornment to the opinion of the expert" is also exacerbated by the fact that expert evidence is resistant to effective cross-examination by counsel who are not experts in that field: *D. (D.)*, at para. 54. The cases address a number of other related concerns: the potential prejudice created by the expert's reliance on unproven material not subject to cross-examination (*D. (D.)*, at para. 55); the risk

of admitting "junk science" (*J. (J.-L.)*, at para. 25); and the risk that a "contest of experts" distracts rather than assists the trier of fact (*Mohan*, at p. 24). Another well-known danger associated with the admissibility of expert evidence is that it may lead to an inordinate expenditure of time and money: *Mohan*, at p. 21; *D.D.*, at para. 56; *Masterpiece Inc. v. Alavida Lifestyles Inc.*, 2011 SCC 27, [2011] 2 S.C.R. 387 (S.C.C.), at para. 76.

19 To address these dangers, *Mohan* established a basic structure for the law relating to the admissibility of expert opinion evidence. That structure has two main components. First, there are four threshold requirements that the proponent of the evidence must establish in order for proposed expert opinion evidence to be admissible: (1) relevance; (2) necessity in assisting the trier of fact; (3) absence of an exclusionary rule; and (4) a properly qualified expert (*Mohan*, at pp. 20-25; see also *Sekhon*, at para. 43). *Mohan* also underlined the important role of trial judges in assessing whether otherwise admissible expert evidence should be excluded because its probative value was overborne by its prejudicial effect — a residual discretion to exclude evidence based on a cost-benefit analysis: p. 21. This is the second component, which the subsequent jurisprudence has further emphasized: Lederman, Bryant and Fuerst, at pp. 789-90; *J. (J.-L.)*, at para. 28.

20 *Mohan* and the jurisprudence since, however, have not explicitly addressed how this "cost-benefit" component fits into the overall analysis. The reasons in *Mohan* engaged in a cost-benefit analysis with respect to particular elements of the four threshold requirements, but they also noted that the cost-benefit analysis could be an aspect of exercising the overall discretion to exclude evidence whose probative value does not justify its admission in light of its potentially prejudicial effects: p. 21. The jurisprudence since *Mohan* has also focused on particular aspects of expert opinion evidence, but again without always being explicit about where additional concerns fit into the analysis. The unmistakable overall trend of the jurisprudence, however, has been to tighten the admissibility requirements and to enhance the judge's gatekeeping role.

21 So, for example, the necessity threshold criterion was emphasized in cases such as *D. (D.)*. The majority underlined that the necessity requirement exists "to ensure that the dangers associated with expert evidence are not lightly tolerated" and that "[m]ere relevance or 'helpfulness' is not enough": para. 46. Other cases have addressed the reliability of the science underlying an opinion and indeed technical evidence in general: *J. (J.-L.)*; *R. v. Trochym*, 2007 SCC 6, [2007] 1 S.C.R. 239 (S.C.C.). The question remains, however, as to where the cost-benefit analysis and concerns such as those about reliability fit into the overall analysis.

22 *Abbey* (ONCA) introduced helpful analytical clarity by dividing the inquiry into two steps. With minor adjustments, I would adopt that approach.

23 At the first step, the proponent of the evidence must establish the threshold requirements of admissibility. These are the four *Mohan* factors (relevance, necessity, absence of an exclusionary rule and a properly qualified expert) and in addition, in the case of an opinion based on novel or contested science or science used for a novel purpose, the reliability of the underlying science for that purpose: *J. (J.-L.)*, at paras. 33, 35-36 and 47; *Trochym*, at para. 27; Lederman, Bryant and Fuerst, at pp. 788-89 and 800-801. Relevance at this threshold stage refers to logical relevance: *Abbey* (ONCA), at para. 82; *J. (J.-L.)*, at para. 47. Evidence that does not meet these threshold requirements should be excluded. Note that I would retain necessity as a threshold requirement: *D. (D.)*, at para. 57; see D. M. Paciocco and L. Stuesser, *The Law of Evidence* (7th ed. 2015), at pp. 209-10; *R. v. Boswell*, 2011 ONCA 283, 85 C.R. (6th) 290 (Ont. C.A.), at para. 13; *R. v. C. (M.)*, 2014 ONCA 611, 13 C.R. (7th) 396 (Ont. C.A.), at para. 72.

24 At the second discretionary gatekeeping step, the judge balances the potential risks and benefits of admitting the evidence in order to decide whether the potential benefits justify the risks. The required balancing exercise has been described in various ways. In *Mohan*, Sopinka J. spoke of the "reliability versus effect factor" (p. 21), while in *J. (J.-L.)*, Binnie J. spoke about "relevance, reliability and necessity" being "measured against the counterweights of consumption of time, prejudice and confusion": para 47. Doherty J.A. summed it up well in *Abbey*, stating that the "trial judge must decide whether expert evidence that meets the preconditions to admissibility is sufficiently beneficial to the trial process to warrant its admission despite the potential harm to the trial process that may flow from the admission of the expert evidence": para. 76.

25 With this delineation of the analytical framework, we can turn to the nature of an expert's duty to the court and where it fits into that framework.

D. The Expert's Duty to the Court or Tribunal

26 There is little controversy about the broad outlines of the expert witness's duty to the court. As Anderson writes, "[t]he duty to provide independent assistance to the Court by way of objective unbiased opinion has been stated many times by common law courts around the world": p. 227. I would add that a similar duty exists in the civil law of Quebec: J.-C. Royer and S. Lavallée, *La preuve civile* (4th ed. 2008), at para. 468; D. Béchard, with the collaboration of J. Béchard, *L'expert* (2011) c. 9; *An Act to establish the new Code of Civil Procedure*, S.Q. 2014, c. 1, *art. 22* (not yet in force); L. Chamberland, *Le nouveau Code de procédure civile commenté* (2014), at pp. 14 and 121.

27 One influential statement of the elements of this duty are found in the English case *National Justice Compania Naviera SA v. Prudential Assurance Co.*, [1993] 2 Lloyd's Rep. 68 (Eng. Comm. Ct.). Following an 87-day trial, Cresswell J. believed that a misunderstanding of the duties and responsibilities of expert witnesses contributed to the length of the trial. He listed in *obiter dictum* duties and responsibilities of experts, the first two of which have particularly influenced the development of Canadian law:

> 1. Expert evidence presented to the Court should be, and should be seen to be, the independent product of the expert uninfluenced as to form or content by the exigencies of litigation ....
>
> 2. An expert witness should provide independent assistance to the Court by way of objective unbiased opinion in relation to matters within his [or her] expertise .... An expert witness in the High Court should never assume the role of an advocate.
>
> [Emphasis added; citation omitted; p. 81.]

(These duties were endorsed on appeal: [*"Ikarian Reefer" (The), Re*] [1995] 1 Lloyd's Rep. 455 (Eng. C.A.), at p. 496.)

28 Many provinces and territories have provided explicit guidance related to the duty of expert witnesses. In Nova Scotia, for example, the *Civil Procedure Rules* require that an expert's report be signed by the expert who must make (among others) the following representations to the court: that the expert is providing an objective opinion for the assistance of the court; that the expert is prepared to apply independent judgment when assisting the court; and that the report includes everything the expert regards as relevant to the expressed opinion and draws attention to anything that could reasonably lead to a different conclusion (r. 55.04(1)(a), (b) and (c)). While these requirements do not affect the rules of evidence by which expert opinion is determined to be admissible or inadmissible, they provide a convenient summary of a fairly broadly shared sense of the duties of an expert witness to the court.

29 There are similar descriptions of the expert's duty in the civil procedure rules in other Canadian jurisdictions: Anderson, at p. 227; *The Queen's Bench Rules (Saskatchewan)*, r. 5-37; *Supreme Court Civil Rules*, B.C. Reg. 168/2009, r. 11-2(1); *Rules of Civil Procedure*, R.R.O. 1990, Reg. 194, r. 4.1.01(1); *Rules of Court*, Y.O.I.C. 2009/65, r. 34(23); *An Act to establish the new Code of Civil Procedure*, art. 22. Moreover, the rules in Saskatchewan, British Columbia, Ontario, Nova Scotia, Prince Edward Island, Quebec and the Federal Courts require experts to certify that they are aware of and will comply with their duty to the court: Anderson, at p. 228; Saskatchewan *Queen's Bench Rules*, r. 5-37(3); British Columbia *Supreme Court Civil Rules*, r. 11-2(2); Ontario *Rules of Civil Procedure*, r. 53.03(2.1); Nova Scotia *Civil Procedure Rules*, r. 55.04(1)(a); Prince Edward Island *Rules of Civil Procedure*, r. 53.03(3)(g); *An Act to establish the new Code of Civil Procedure*, art. 235 (not yet in force); *Federal Courts Rules*, SOR/98-106, r. 52.2(1)(c).

30 The formulation in the *Ontario Rules of Civil Procedure* is perhaps the most succinct and complete statement of the expert's duty to the court: to provide opinion evidence that is fair, objective and non-partisan: r. 4.1.01(1)(a). The Rules are also explicit that this duty to the court prevails over any obligation owed by the expert to a party: r. 4.1.01(2). Likewise, the newly adopted *Act to establish the new Code of Civil Procedure of Quebec* explicitly provides, as a guiding principle, that the expert's

duty to the court overrides the parties' interests, and that the expert must fulfill his or her primary duty to the court "objectively, impartially and thoroughly": art. 22; Chamberland, at pp. 14 and 121.

31 Many of the relevant rules of court simply reflect the duty that an expert witness owes to the court at common law: Anderson, at p. 227. In my opinion, this is true of the Nova Scotia rules that apply in this case. Of course, it is always open to each jurisdiction to impose different rules of admissibility, but in the absence of a clear indication to that effect, the common law rules apply in common law cases. I note that in *Nova Scotia, the Civil Procedure Rules* explicitly provide that they do not change the rules of evidence by which the admissibility of expert opinion evidence is determined: r. 55.01(2).

32 Underlying the various formulations of the duty are three related concepts: impartiality, independence and absence of bias. The expert's opinion must be impartial in the sense that it reflects an objective assessment of the questions at hand. It must be independent in the sense that it is the product of the expert's independent judgment, uninfluenced by who has retained him or her or the outcome of the litigation. It must be unbiased in the sense that it does not unfairly favour one party's position over another. The acid test is whether the expert's opinion would not change regardless of which party retained him or her: P. Michell and R. Mandhane, "The Uncertain Duty of the Expert Witness" (2005), 42 *Alta. L. Rev.* 635, at pp. 638-39. These concepts, of course, must be applied to the realities of adversary litigation. Experts are generally retained, instructed and paid by one of the adversaries. These facts alone do not undermine the expert's independence, impartiality and freedom from bias.

E. The Expert's Duties and Admissibility

33 As we have seen, there is a broad consensus about the nature of an expert's duty to the court. There is no such consensus, however, about how that duty relates to the admissibility of an expert's evidence. There are two main questions: Should the elements of this duty go to admissibility of the evidence rather than simply to its weight?; And, if so, is there a threshold admissibility requirement in relation to independence and impartiality?

34 In this section, I will explain my view that the answer to both questions is yes: a proposed expert's independence and impartiality go to admissibility and not simply to weight and there is a threshold admissibility requirement in relation to this duty. Once that threshold is met, remaining concerns about the expert's compliance with his or her duty should be considered as part of the overall cost-benefit analysis which the judge conducts to carry out his or her gatekeeping role.

(1) Admissibility or Only Weight?

(a) The Canadian Law

35 The weight of authority strongly supports the conclusion that at a certain point, expert evidence should be ruled inadmissible due to the expert's lack of impartiality and/or independence.

36 Our Court has confirmed this position in a recent decision that was not available to the courts below:

> It is well established that an expert's opinion must be independent, impartial and objective, and given with a view to providing assistance to the decision maker (J.-C. Royer and S. Lavallée, *La preuve civile* (4th ed. 2008), at No. 468; D. Béchard, with the collaboration of J. Béchard, *L'expert* (2011), chap. 9; *An Act to establish the new Code of Civil Procedure*, S.Q. 2014, c. 1, s. 22 (not yet in force)). However, these factors generally have an impact on the probative value of the expert's opinion and are not always insurmountable barriers to the admissibility of his or her testimony. Nor do they necessarily "disqualify" the expert (L. Ducharme and C.- M. Panaccio, *L'administration de la preuve* (4th ed. 2010), at Nos. 590-91 and 605). For expert testimony to be inadmissible, more than a simple appearance of bias is necessary. The question is not whether a reasonable person would consider that the expert is not independent. Rather, what must be determined is whether the expert's lack of independence renders him or her incapable of giving an impartial opinion in the specific circumstances of the case (D. M. Paciocco, "Unplugging Jukebox Testimony in an Adversarial System: Strategies for Changing the Tune on Partial Experts" (2009), 34 *Queen's L.J.* 565, at pp. 598-99).
>
> (*Mouvement laïque québécois v. Saguenay (City)*, 2015 SCC 16, at para. 106)

37 I will refer to a number of other cases that support this view. I do so by way of illustration and without commenting on the outcome of particular cases. An expert's interest in the litigation or relationship to the parties has led to exclusion in a number of cases: see, e.g., *Fellowes, McNeil v. Kansa General International Insurance Co.* (1998), 40 O.R. (3d) 456 (Ont. Gen. Div.) (proposed expert was the defendant's lawyer in related matters and had investigated from the outset of his retainer the matter of a potential negligence claim against the plaintiff); *CC&L Dedicated Enterprise Fund (Trustee of) v. Fisherman* (2000), 49 O.R. (3d) 187 (Ont. S.C.J.) (expert was the party's lawyer in related U.S. proceedings); *R. v. Docherty*, 2010 ONSC 3628 (Ont. S.C.J.) (expert was the defence counsel's father); *Ocean v. Economical Mutual Insurance Co.*, 2010 NSSC 315, 293 N.S.R. (2d) 394 (N.S. S.C.) (expert was also a party to the litigation); *Handley v. Punnett*, 2003 BCSC 294 (B.C. S.C.) (expert was also a party to the litigation); *Bank of Montreal v. Citak*, [2001] O.J. No. 1096 (Ont. S.C.J. [Commercial List]) (expert was effectively a "co-venturer" in the case due in part to the fact that 40 percent of his remuneration was contingent upon success at trial: para. 7); *Dean Construction Co. v. M.J. Dixon Construction Ltd.*, 2011 ONSC 4629, 5 C.L.R. (4th) 240 (Ont. Master) (expert's retainer agreement was inappropriate); *Hutchingame v. Johnstone*, 2006 BCSC 271 (B.C. S.C.) (expert stood to incur liability depending on the result of the trial). In other cases, the expert's stance or behaviour as an advocate has justified exclusion: see, e.g., *Carmen Alfano Family Trust v. Piersanti*, 2012 ONCA 297, 291 O.A.C. 62 (Ont. C.A.); *Kirby Lowbed Services Ltd. v. Bank of Nova Scotia*, 2003 BCSC 617 (B.C. S.C.); *Gould v. Western Coal Corp.*, 2012 ONSC 5184, 7 B.L.R. (5th) 19 (Ont. S.C.J.).

38 Many other cases have accepted, in principle, that lack of independence or impartiality can lead to exclusion, but have ruled that the expert evidence did not warrant rejection on the particular facts: see, e.g., *United City Properties Ltd. v. Tong*, 2010 BCSC 111 (B.C. S.C.); *R. v. Inco Ltd.* (2006), 80 O.R. (3d) 594 (Ont. S.C.J.). This was the position of the Court of Appeal in this case: para. 109; see also para. 121.

39 Some Canadian courts, however, have treated these matters as going exclusively to weight rather than to admissibility. The most often cited cases for this proposition are probably *R. v. Klassen*, 2003 MBQB 253, 179 Man. R. (2d) 115 (Man. Q.B.), and *Gallant v. Brake-Patten*, 2012 NLCA 23, 321 Nfld. & P.E.I.R. 77 (N.L. C.A.). *Klassen* holds as admissible any expert evidence meeting the criteria from *Mohan*, with bias only becoming a factor as to the weight to be given to the evidence: see also *R. v. Violette*, 2008 BCSC 920 (B.C. S.C.). Similarly, the court in *Gallant* determined that a challenge to expert evidence that is based on the expert having a connection to a party or an issue in the case or a possible predetermined position on the case cannot take place at the admissibility stage: para. 89.

40 I conclude that the dominant approach in Canadian common law is to treat independence and impartiality as bearing not just on the weight but also on the admissibility of the evidence. I note that while the shareholders submit that issues regarding expert independence should go only to weight, they rely on cases such as *INCO* that specifically accept that a finding of lack of independence or impartiality can lead to inadmissibility in certain circumstances: R.F., at paras. 52-53.

(b) Other Jurisdictions

41 Outside Canada, the concerns related to independence and impartiality have been addressed in a number of ways. Some are similar to the approach in Canadian law.

42 For example, summarizing the applicable principles in British law, Nelson J. in *Armchair Passenger Transport Ltd. v. Helical Bar Plc*, [2003] EWHC 367 (Eng. & Wales H.C. [T. & C.C.]), underlined that when an expert has an interest or connection with the litigation or a party thereto, exclusion will be warranted if it is determined that the expert is unwilling or unable to carry out his or her primary duty to the court: see also H. M. Malek et al., eds., *Phipson on Evidence* (18th ed. 2013), at pp. 1158-59. The mere fact of an interest or connection will not disqualify, but it nonetheless may do so in light of the nature and extent of the interest or connection in particular circumstances. As Lord Phillips of Worth Matravers, M.R., put it in a leading case, "[i]t is always desirable that an expert should have no actual or apparent interest in the outcome of the proceedings in which he gives evidence, but such disinterest is not automatically a precondition to the admissibility of his evidence": *Factortame Ltd. v. Secretary of State for the Environment, Transport & the Regions (Costs) (No.2)* (2002), [2002] EWCA Civ 932, [2003] Q.B. 381 (Eng. C.A.), at para. 70; see also *Gallaher International Ltd. v. Tlais Enterprises Ltd.*, [2007] EWHC 464 (Eng. Comm.

Ct.); *Meat Corp. of Namibia Ltd. v. Dawn Meats (U.K.) Ltd.*, [2011] EWHC 474 (Eng. Ch. Div.); *Matchbet Ltd. v. Openbet Retail Ltd.*, [2013] EWHC 3067 (Eng. Ch. Div.), at paras. 312-17.

43 In Australia, the expert's objectivity and impartiality will generally go to weight, not to admissibility: I. Freckelton and H. Selby, *Expert Evidence: Law, Practice, Procedure and Advocacy* (5th ed. 2013), at p. 35. As the Court of Appeal of the State of Victoria put it: "... to the extent that it is desirable that expert witnesses should be under a duty to assist the Court, that has not been held and should not be held as disqualifying, in itself, an 'interested' witness from being competent to give expert evidence" (*FGT Custodians Pty Ltd. v. Fagenblat*, [2003] VSCA 33 (Australia Vic. Sup. Ct.), at para. 26 (AustLII); see also Freckelton and Selby, at pp. 186-88; *Collins Thomson Ltd. v. Clayton*, [2002] NSWSC 366 (New South Wales S.C.); *Kirch Communications Pty Ltd. v. Gene Engineering Pty Ltd.*, [2002] NSWSC 485 (New South Wales S.C.); *SmithKline Beecham (Australia) Pty Ltd. v. Chipman*, [2003] FCA 796, 131 F.C.R. 500 (Australia Fed. Ct.)).

44 In the United States, at the federal level, the independence of the expert is a consideration that goes to the weight of the evidence, and a party may testify as an expert in his own case: *Rodriguez v. Pacificare of Texas Inc.* (1993), 980 F.2d 1014 (U.S. C.A. 5th Cir. 1993), at p. 1019; *Tagatz v. Marquette University* (1988), 861 F.2d 1040 (U.S. C.A. 7th Cir. 1988); *Apple Inc. v. Motorola, Inc.* (2014), 757 F.3d 1286 (U.S. C.A. Fed. Cir.), at p. 1321. This also seems to be a fair characterization of the situation in the states: *Corpus Juris Secundum*, vol. 32 (2008), at p. 325: "The bias or interest of the witness does not affect his or her qualification, but only the weight to be given the testimony.".

(c) Conclusion

45 Following what I take to be the dominant view in the Canadian cases, I would hold that an expert's lack of independence and impartiality goes to the admissibility of the evidence in addition to being considered in relation to the weight to be given to the evidence if admitted. That approach seems to me to be more in line with the basic structure of our law relating to expert evidence and with the importance our jurisprudence has attached to the gatekeeping role of trial judges. Binnie J. summed up the Canadian approach well in *J. (J.-L.)*: "The admissibility of the expert evidence should be scrutinized at the time it is proffered, and not allowed too easy an entry on the basis that all of the frailties could go at the end of the day to weight rather than admissibility" (para. 28).

(2) The Appropriate Threshold

46 I have already described the duty owed by an expert witness to the court: the expert must be fair, objective and non-partisan. As I see it, the appropriate threshold for admissibility flows from this duty. I agree with Prof. (now Justice of the Ontario Court of Justice) Paciocco that "the common law has come to accept ... that expert witnesses have a duty to assist the court that overrides their obligation to the party calling them. If a witness is unable or unwilling to fulfill that duty, they do not qualify to perform the role of an expert and should be excluded": "Taking a 'Goudge' out of Bluster and Blarney: an 'Evidence-Based Approach' to Expert Testimony" (2009), 13 *Can. Crim. L. R.* 135, at p. 152 (footnote omitted). The expert witnesses must, therefore, be aware of this primary duty to the court and able and willing to carry it out.

47 Imposing this additional threshold requirement is not intended to and should not result in trials becoming longer or more complex. As Prof. Paciocco aptly observed, "if inquiries about bias or partiality become routine during *Mohan voir dires*, trial testimony will become nothing more than an inefficient reprise of the admissibility hearing": "Unplugging Jukebox Testimony in an Adversarial System: Strategies for Changing the Tune on Partial Experts" (2009), 34 *Queen's L.J.* 565 ("Jukebox"), at p. 597. While I would not go so far as to hold that the expert's independence and impartiality should be presumed absent challenge, my view is that absent such challenge, the expert's attestation or testimony recognizing and accepting the duty will generally be sufficient to establish that this threshold is met.

48 Once the expert attests or testifies on oath to this effect, the burden is on the party opposing the admission of the evidence to show that there is a realistic concern that the expert's evidence should not be received because the expert is unable and/or unwilling to comply with that duty. If the opponent does so, the burden to establish on a balance of probabilities this aspect of the admissibility threshold remains on the party proposing to call the evidence. If this is not done, the evidence, or those

parts of it that are tainted by a lack of independence or impartiality, should be excluded. This approach conforms to the general rule under the *Mohan* framework, and elsewhere in the law of evidence, that the proponent of the evidence has the burden of establishing its admissibility.

49 This threshold requirement is not particularly onerous and it will likely be quite rare that a proposed expert's evidence would be ruled inadmissible for failing to meet it. The trial judge must determine, having regard to both the particular circumstances of the proposed expert and the substance of the proposed evidence, whether the expert is able and willing to carry out his or her primary duty to the court. For example, it is the nature and extent of the interest or connection with the litigation or a party thereto which matters, not the mere fact of the interest or connection; the existence of some interest or a relationship does not automatically render the evidence of the proposed expert inadmissible. In most cases, a mere employment relationship with the party calling the evidence will be insufficient to do so. On the other hand, a direct financial interest in the outcome of the litigation will be of more concern. The same can be said in the case of a very close familial relationship with one of the parties or situations in which the proposed expert will probably incur professional liability if his or her opinion is not accepted by the court. Similarly, an expert who, in his or her proposed evidence or otherwise, assumes the role of an advocate for a party is clearly unwilling and/or unable to carry out the primary duty to the court. I emphasize that exclusion at the threshold stage of the analysis should occur only in very clear cases in which the proposed expert is unable or unwilling to provide the court with fair, objective and non-partisan evidence. Anything less than clear unwillingness or inability to do so should not lead to exclusion, but be taken into account in the overall weighing of costs and benefits of receiving the evidence.

50 As discussed in the English case law, the decision as to whether an expert should be permitted to give evidence despite having an interest or connection with the litigation is a matter of fact and degree. The concept of apparent bias is not relevant to the question of whether or not an expert witness will be unable or unwilling to fulfill its primary duty to the court. When looking at an expert's interest or relationship with a party, the question is not whether a reasonable observer would think that the expert is not independent. The question is whether the relationship or interest results in the expert being unable or unwilling to carry out his or her primary duty to the court to provide fair, non-partisan and objective assistance.

51 Having established the analytical framework, described the expert's duty and determined that compliance with this duty goes to admissibility and not simply to weight, I turn now to where this duty fits into the analytical framework for admission of expert opinion evidence.

F. Situating the Analysis in the Mohan Framework

(1) The Threshold Inquiry

52 Courts have addressed independence and impartiality at various points of the admissibility test. Almost every branch of the *Mohan* framework has been adapted to incorporate bias concerns one way or another: the proper qualifications component (see, e.g., *Bank of Montreal*; *Dean Construction*; *Agribrands Purina Canada Inc. v. Kasamekas*, 2010 ONSC 166 (Ont. S.C.J.); *R. v. Demetrius* [2009 CarswellOnt 2548 (Ont. S.C.J.)], 2009 CanLII 22797; the necessity component (see, e.g., *Docherty; Alfano*); and during the discretionary cost-benefit analysis (see, e.g., *United City Properties*; *Abbey* (ONCA)). On other occasions, courts have found it to be a stand-alone requirement: see, e.g., *Docherty*; *International Hi-Tech Industries Inc. v. FANUC Robotics Canada Ltd.*, 2006 BCSC 2011 (B.C. S.C.); *Casurina Ltd. Partnership v. Rio Algom Ltd.* (2002), 28 B.L.R. (3d) 44 (Ont. S.C.J. [Commercial List]); *Prairie Well Servicing Ltd. v. Tundra Oil & Gas Ltd.*, 2000 MBQB 52, 146 Man. R. (2d) 284 (Man. Q.B.). Some clarification of this point will therefore be useful.

53 In my opinion, concerns related to the expert's duty to the court and his or her willingness and capacity to comply with it are best addressed initially in the "qualified expert" element of the *Mohan* framework: S. C. Hill, D. M. Tanovich and L. P. Strezos, *McWilliams' Canadian Criminal Evidence* (5th ed. (loose-leaf)), at s. 12:30.20.50; see also *Deemar v. College of Veterinarians (Ontario)*, 2008 ONCA 600, 92 O.R. (3d) 97 (Ont. C.A.), at para. 21; Lederman, Bryant and Fuerst, at pp. 826-27; *Halsbury's Laws of Canada: Evidence*, at para. HEV-152 "Partiality"; *The Canadian Encyclopedic Digest* (Ont. 4th ed. (loose-leaf)), vol. 24, Title 62 — Evidence, at § 469. A proposed expert witness who is unable or unwilling to fulfill this duty to the court is not properly qualified to perform the role of an expert. Situating this concern in the "properly qualified expert"

ensures that the courts will focus expressly on the important risks associated with biased experts: Hill, Tanovich and Strezos, at s. 12:30.20.50; Paciocco, "Jukebox", at p. 595.

(2) The Gatekeeping Exclusionary Discretion

54 Finding that expert evidence meets the basic threshold does not end the inquiry. Consistent with the structure of the analysis developed following *Mohan* which I have discussed earlier, the judge must still take concerns about the expert's independence and impartiality into account in weighing the evidence at the gatekeeping stage. At this point, relevance, necessity, reliability and absence of bias can helpfully be seen as part of a sliding scale where a basic level must first be achieved in order to meet the admissibility threshold and thereafter continue to play a role in weighing the overall competing considerations in admitting the evidence. At the end of the day, the judge must be satisfied that the potential helpfulness of the evidence is not outweighed by the risk of the dangers materializing that are associated with expert evidence.

G. Expert Evidence and Summary Judgment

55 I must say a brief word about the procedural context in which this case originates — a summary judgment motion. (I note that these comments relate to the summary judgment regime under the Nova Scotia rules and that different considerations may arise under different rules.) It is common ground that the court hearing the motion can consider only admissible evidence. However, under the Nova Scotia jurisprudence, which is not questioned on this appeal, it is not the role of a judge hearing a summary judgment motion in Nova Scotia to weigh the evidence, draw reasonable inferences from evidence or settle matters of credibility: *Coady v. Burton Canada Co.*, 2013 NSCA 95, 333 N.S.R. (2d) 348 (N.S. C.A.), at paras. 42-44, 87 and 98; *Fougere v. Blunden Construction Ltd.*, 2014 NSCA 52, 345 N.S.R. (2d) 385 (N.S. C.A.), at paras. 6 and 12. Taking these two principles together, the result in my view is this. A motions judge hearing a summary judgment application under the Nova Scotia rules must be satisfied that proposed expert evidence meets the threshold requirements for admissibility at the first step of the analysis, but should generally not engage in the second step cost-benefit analysis. That cost-benefit analysis, in anything other than the most obvious cases of inadmissibility, inevitably involves assigning weight — or at least potential weight — to the evidence.

H. Application

56 I turn to the application of these principles to the facts of the case. In my respectful view, the record amply sustains the result reached by the majority of the Court of Appeal that Ms. MacMillan's evidence was admissible on the summary judgment application. Of course, the framework which I have set out in these reasons was not available to either the motions judge or to the Court of Appeal.

57 There was no finding by the motions judge that Ms. MacMillan was in fact biased or not impartial or that she was acting as an advocate for the shareholders: C.A. reasons, at para. 122. On the contrary, she specifically recognized that she was aware of the standards and requirements that experts be independent. She was aware of the precise guidelines in the accounting industry concerning accountants acting as expert witnesses. She testified that she owed an ultimate duty to the court in testifying as an expert witness: A.R., vol. III, at pp. 75-76; C.A. reasons, at para. 134. To the extent that the motions judge was concerned about the "appearance" of impartiality, this factor plays no part in the test for admissibility, as I have explained earlier.

58 The auditors' claim that Ms. MacMillan lacks objectivity rests on two main points which I will address in turn.

59 First, the auditors say that the earlier work done for the shareholders by the Kentville office of Grant Thornton "served as a catalyst and foundation for the claim of negligence" against the auditors and that this "precluded [Grant Thornton] from acting as 'independent' experts in this case": A.F., at paras. 17 and 19. Ms. MacMilllan, the auditors submit, was in an "irreconcilable conflict of interest, in that she would inevitably have to opine on, and choose between, the actions taken and standard of care exercised by her own partners at Grant Thornton" and those of the auditors: A.F., at para. 21. This first submission, however, must be rejected.

60 The fact that one professional firm discovers what it thinks is or may be professional negligence does not, on its own, disqualify it from offering that opinion as an expert witness. Provided that the initial work is done independently and impartially

and the person put forward as an expert understands and is able to comply with the duty to provide fair, objective and non-partisan assistance to the court, the expert meets the threshold qualification in that regard. There is no suggestion here that Grant Thornton was hired to take a position dictated to it by the shareholders or that there was anything more than a speculative possibility of Grant Thornton incurring liability to them if the firm's opinion was not ultimately accepted by the court. There was no finding that Ms. MacMillan was, in fact, biased or not impartial, or that she was acting as an advocate for the shareholders. The auditors' submission that she somehow "admitted" on her cross-examination that she was in an "irreconcilable conflict" is not borne out by a fair reading of her evidence in context: A.R., vol. III, at pp. 139-45. On the contrary, her evidence was clear that she understood her role as an expert and her duty to the court: *ibid.*, at pp. 75-76.

61 The auditors' second main point was that Ms. MacMillan was not independent because she had "incorporated" some of the work done by the Kentville office of her firm. This contention is also ill founded. To begin, I do not accept that an expert lacks the threshold qualification in relation to the duty to give fair, objective and non-partisan evidence simply because the expert relies on the work of other professionals in reaching his or her own opinion. Moreover, as Beveridge J.A. concluded, what was "incorporated" was essentially an exercise in arithmetic that had nothing to do with any accounting opinion expressed by the Kentville office: C.A. reasons, at paras. 146-49.

62 There was no basis disclosed in this record to find that Ms. MacMillan's evidence should be excluded because she was not able and willing to provide the court with fair, objective and non-partisan evidence. I agree with the majority of the Court of Appeal who concluded that the motions judge committed a palpable and overriding error in determining that Ms. MacMillan was in a conflict of interest that prevented her from giving impartial and objective evidence: paras. 136-50.

IV. Disposition

63 I would dismiss the appeal with costs.

Appeal dismissed.

Pourvoi rejeté.

2020 MBCA 60
Manitoba Court of Appeal

Manitoba (Hydro-Electric Board) v. Manitoba (Public Utilities Board) et al

2020 CarswellMan 354, 2020 MBCA 60, [2020] M.J. No. 135, [2021] 3 W.W.R. 335, 328 A.C.W.S. (3d) 853

IN THE MATTER OF: The Public Utilities Board Act, CCSM c P280

IN THE MATTER OF: The Manitoba Hydro Act, CCSM c H190

IN THE MATTER OF: The Crown Corporations Governance and Accountability Act, CCSM c C336

IN THE MATTER OF: An Appeal from Order No. 59/18 dated May 1, 2018, Order No. 68/18 dated May 29, 2018 and Order No. 90/18 dated July 13, 2018 of the Public Utilities Board of Manitoba

MANITOBA HYDRO-ELECTRIC BOARD (Applicant / Appellant) and PUBLIC UTILITIES BOARD OF MANITOBA (Respondent) and CONSUMERS' ASSOCIATION OF CANADA (MANITOBA) and ASSEMBLY OF MANITOBA CHIEFS (Interveners)

Diana M. Cameron, William J. Burnett, Janice L. leMaistre JJ.A.

Heard: January 22, 2020
Judgment: June 9, 2020
Docket: AI 18-30-09116

Counsel: P.J. Ramage, H.D. Van Iderstine, D.A. Barchyn, for Appellant
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J.B. Williams, for Intervener, Consumers' Association of Canada
C. Fox, E. Guglielmin, for Intervener, Assembly of Manitoba Chiefs

***Diana M. Cameron J.A.*:**

Introduction and Background

1 This is an appeal by the applicant (Manitoba Hydro) from Directive 6 (the directive) of Order No 59/18 of the respondent (the PUB) (all PUB orders referred to herein were accessed online: *Public Utilities Board*, <www.pubmanitoba.ca/v1/proceedings-decisions/orders/electricity.h tml> (date accessed: 26 May 2020)). Order No 59/18 was made in response to a General Rate Application filed by Manitoba Hydro seeking, among other things, a 7.9 per cent rate increase to all components of the rates for all customer classes to be effective April 1, 2018.

2 The PUB unanimously denied the 7.9 per cent increase, ordering instead a 3.6 per cent average revenue increase. However, by way of the directive, a majority of the PUB ordered Manitoba Hydro to create a First Nations On-Reserve Residential customer class (the on-reserve class) that was to receive a zero per cent rate increase.

3 The sole dissenting member of the PUB was of the opinion that the PUB did not have jurisdiction to create the on-reserve class.

4 In *Manitoba Hydro-Electric Board v. Public Utilities Board (Man) et al*, 2019 MBCA 54 (Man. C.A.), leave to appeal the directive to this Court was granted by Michel Monnin JA pursuant to section 58(2) of The Public Utilities Board Act, CCSM c

P280 (the PUB Act) on the question of "whether the PUB exceeded its jurisdiction in creating [an on-reserve class] whose rate for service would be different from those customers remaining in the existing 'residential class'" (at para 41).

5 After the directive had been made, the PUB approved the resulting Residential Rates Schedule reflecting the new rates in Order No 68/16 [*Manitoba Hydro, Re* (May 17, 2016), Doc. 68/16 (Man. P.U.C.)].

6 Manitoba Hydro applied to the PUB to review and vary Order Nos 59/18 [May 01, 2018Doc. 59/18Man. P.U.C.] and 68/18 [May 29, 2018Doc. 68/18 (Man. P.U.C.)] including, among other things, the directive. In Order No 90/18 [July 13, 2018Doc. 90/18 (Man. P.U.C.)], the PUB denied the application to vary the directive. Thus, to the extent that Order Nos 68/18 and 90/18 reflect the directive contained in Order No 59/18, they are also the subject of this appeal.

7 Manitoba Hydro maintains that, in creating the on-reserve class, the PUB exceeded its jurisdiction. In support of its argument, it relies on statutory interpretation of *The* Manitoba Hydro Act, CCSM c H190 (the Hydro Act) ; the PUB Act; and The Crown Corporations Governance and Accountability Act, CCSM c C336 (the *Crown Act*).

8 Relying on the same statutes, the PUB asserts that, in exercising its function of reviewing and setting rates for the provision of power, it is empowered to consider policy issues such as energy affordability for "low-income families" (Order No 59/18 at p 209). It maintains that it has the jurisdiction to "order a bill affordability program such as a lower-income rate, and to take into account affordability as a factor in setting just and reasonable rates" (at p 27). In its view, it was exercising this jurisdiction when it directed the creation of the on-reserve class.

9 Consumers' Association of Canada (Manitoba) (CAC Manitoba) generally supports the position of the PUB. Its primary focus is to rebut Manitoba Hydro's assertion that the PUB erred by determining that it had the authority to classify customer groups.

10 Assembly of Manitoba Chiefs (AMC) is in total agreement with the position of the PUB. It emphasises that, in reaching its conclusion, the PUB correctly considered *The* Path to Reconciliation Act, CCSM c R30.5 (the *PTRA*).

11 For the reasons below, I would allow the appeal. While the PUB has the authority to scrutinize and create customer classifications in approving the rates charged by Manitoba Hydro, the directive breached section 39(2.2) of the Hydro Act, which requires that customers are not to be classified solely on the basis of the region of the province in which they live or the density of the population.

12 In addition, and more significantly, the directive constituted the creation and implementation of general social policy, an area outside of the PUB's jurisdiction and encroaching into areas that are better suited to the federal and provincial governments. The directive resulted in the use of Manitoba Hydro's funds and revenue for government purposes contrary to section 43(3) of the Hydro Act and in excess of the PUB's jurisdiction.

The Legislative Framework

Manitoba Hydro

Manitoba Hydro is a Crown corporation with a monopoly over the provision of power in Manitoba. Its home statute, the *Hydro Act*, specifies that its objects and purposes are to "provide for the continuance of a supply of power adequate for the needs of the province" and related activities (at section 2). Section 39(1) of the Hydro Act provides that "The prices payable for power supplied by [Manitoba Hydro] shall be such as to return to it in full the cost to the corporation, of supplying the power". Section 39(2) grants Manitoba Hydro the ability to fix prices subject to Part 4 of the Crown Act.

The PUB

13 The home statute of the PUB is the PUB Act. The PUB describes itself as "an administrative tribunal created by provincial legislation to act as an independent decision-maker in the regulation of public utilities in Manitoba" (Order 59/18 at p 4). The

PUB's authority over Manitoba Hydro is limited by section 2(5) of the PUB Act, which provides, "Subject to Part 4 of the [*Crown Act*] ... this Act ... does not apply to Manitoba Hydro and the [PUB] has no jurisdiction or authority over Manitoba Hydro."

The Crown Act

14 The *Crown Act* governs public corporations, including Manitoba Hydro (see section 2(b)). Section 25(1) provides that the PUB shall review the rates for services provided by Manitoba Hydro. Section 25(2) defines rates for services as the prices charged by Manitoba Hydro for the provision of power. Section 25(3) states that the PUB Act applies with "any necessary changes" to a review of the rates for services charged by Manitoba Hydro for the provision of power. Finally, section 25(4) provides a number of factors that the PUB may take into consideration in making a decision regarding the rates for services.

15 The relevant provisions of the *Hydro Act*, the *PUB Act* and the *Crown Act* are reproduced in full in these reasons as required.

The Decision of the PUB

16 The PUB determined it had broad jurisdiction with respect to its review of the rates charged by Manitoba Hydro. It found that, when fixing just and reasonable rates pursuant to section 77 of the PUB Act, it was guided by the factors contained in section 25(4)(a) of the Crown Act, including section 25(4)(a)(viii), which allows the PUB to consider any compelling policy considerations, and section 25(4)(a)(ix), which allows it to take into account any other factors it considers to be relevant to the matter. The PUB stated (at p 217):

> As the Manitoba Court of Appeal held in *Consumers' Association of Canada (Manitoba) Inc v Manitoba Hydro Electric Board*, 2005 MBCA 55, this requires the [PUB] to balance two concerns: "the interests of the utility's ratepayers, and the financial health of the utility. Together, and in the broadest interpretation, these interests represent the general public interest." Each of these two concerns support the ability of the [PUB] to consider the affordability of Manitoba Hydro's rates, whether broadly or within a class or sub-set of its customers.

17 The PUB further determined that the PUB Act did not prohibit the creation of a customer class that pays less than the average cost to serve such customers. According to the PUB, "the only limitation on the [PUB's] broad authority under *The Crown Act* is the requirement [at section 39(2.2)(b) of the Hydro Act] that customers not be classified solely based on region or population density" (at p 220). It was the PUB's view that the creation of a lower-income customer class generally was not prohibited by that limitation.

18 In brief, the PUB concluded that it had "legal jurisdiction under its governing statutory framework to order a bill affordability program such as a lower-income rate, and to take into account affordability as a factor in setting just and reasonable rates" (at p 27).

19 Based on the foregoing, the PUB directed Manitoba Hydro to establish the on-reserve class and implement a zero per cent rate increase for that class for the 2018/2019 test year. In its reasons, the PUB stated that the directive was consistent with the principle of reconciliation as defined in the *PTRA*. It said that the creation of the on-reserve class was in response to the degree of poverty on reserves and ordered that the on-reserve class continue until otherwise ordered. According to the PUB, the creation of the on-reserve class was "not defined solely on the basis of the region of the province in which the customers are located or population density" (at p 233).

20 In reaching its conclusion, the PUB recognised that the directive could create a shortfall in revenue to Manitoba Hydro. However, it determined that Manitoba Hydro would be "kept whole because the cost of the 0% rate increase for [the on-reserve class] has been factored into the level of the average general rate increase granted for the Test Year to all other customer classes" (at p 29).

21 The dissenting member of the PUB found that the directive constituted a departure from principles of utility regulation in this province. He stated that, if there was to be a "significant deviation or change to the long-standing approach to cost recovery on a cost of service basis, that change should be made by the Government" (at p 236). In his view, the creation of the sub-set of

residential payers constituted the impermissible making of social policy. While he agreed with the majority that the PUB had the jurisdiction to create a lower-income customer class, it did not have jurisdiction to create a "discriminatory customer class based on regions of the province" (at p 237). Finally, he expressed concern that, over time, the gap in residential rates would continue to grow and "would become onerous on other ratepayers that will be responsible for subsidizing through their rates the lost revenues not recovered from the [on-reserve class]" (at p 238).

Grounds of Appeal

22 Manitoba Hydro raises six grounds of appeal:

1. Did the PUB misinterpret the legislative schemes governing Manitoba Hydro and the PUB?

2. Did the PUB err in its understanding of the uniform rates provision of the *Hydro Act* and the regulatory principle of non-discrimination?

3. Did the PUB err in its definition of reserve?

4. Did the PUB err in its application of the limited class rule?

5. Did the PUB err in law in intruding into social policy?

6. Did the PUB err in causing Manitoba Hydro to expend funds for purposes of poverty reduction (Government purposes)?

Standard of Review

23 This case involves an appeal of the decision of an administrative tribunal. Before the hearing of this matter, the Supreme Court of Canada released its decision in *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65 (S.C.C.), and the companion decision of *Bell Canada v. Canada (Attorney General)*, 2019 SCC 66 (S.C.C.).

24 In *Vavilov*, the Supreme Court of Canada reinforced that reasonableness is the presumptive standard to be applied by a court reviewing the merits of an administrative law decision (see paras 10, 16, 25). However, relevant to this case, an intent to rebut the presumption of reasonableness can be found where the legislation provides a statutory appeal mechanism from an administrative decision to the courts (see paras 17, 33).

25 Where a court is hearing an appeal pursuant to a statutory appeal mechanism, the court is to apply appellate standards of review as set out in *Housen v. Nikolaisen*, 2002 SCC 33 (S.C.C.). Thus, where the appeal is from an administrative decision-maker, and a question of law is raised, including questions of statutory interpretation and questions about the scope of the decision-maker's authority, the standard of correctness will apply. If the issue is a question of fact, or a question of mixed law and fact for which there is no extricable question of law, the standard of palpable and overriding error will apply (see para 37).

26 Section 58(1) of the PUB Act states:

> **Grounds of appeal**
>
> **58(1)** An appeal lies from any final order or decision of the [PUB] to The Court of Appeal upon
>
> (a) any question involving the jurisdiction of the [PUB]; or
>
> (b) any point of law; or
>
> (c) any facts expressly found by the [PUB] relating to a matter before the [PUB].

27 The parties agree, as do I, that the question of "whether the PUB exceeded its jurisdiction in creating [an on-reserve class] whose rate for service would be different from those customers remaining in the existing ‘residential class’" (2019 MBCA 54

(Man. C.A.) at para 41) involves issues of statutory interpretation and is therefore to be reviewed on the standard of correctness (see *Bell Canada* at paras 34-35). In my view, the standard of correctness also applies to each of the grounds of appeal advanced by Manitoba Hydro as they involve questions of jurisdiction, statutory interpretation and law.

Statutory Interpretation

28 The modern approach to statutory interpretation was set out by the Supreme Court of Canada in *Rizzo & Rizzo Shoes Ltd., Re*, [1998] 1 S.C.R. 27 (S.C.C.) (at para 21):

> Although much has been written about the interpretation of legislation, ... Elmer Driedger in *Construction of Statutes* (2nd ed. 1983) best encapsulates the approach upon which I prefer to rely. He recognizes that statutory interpretation cannot be founded on the wording of the legislation alone. At p. 87 he states:
>
>> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

29 Further, section 6 of The Interpretation Act, CCSM c I80 provides that "[e]very Act and regulation must be interpreted as being remedial and must be given the fair, large and liberal interpretation that best ensures the attainment of its objects."

Ground 1 — Did the PUB Misinterpret the Legislative Schemes Governing Manitoba Hydro and the PUB?

Positions of the Parties

30 Manitoba Hydro underscores that it is generally exempt from the PUB Act pursuant to section 2(5) of that Act. It argues that the PUB's grant of authority pursuant to section 25 of the Crown Act only permits the PUB to review "rates for service", that being the price charged by Manitoba Hydro with respect to the provision of power. It submits that there is no authority permitting the PUB to create customer classes.

31 The PUB argues that section 25(3) of the Crown Act authorises it to apply the PUB Act to the review of rates charged by Manitoba Hydro and that its ability to create classes is found in sections 77 and 82(1) of the PUB Act.

32 CAC Manitoba argues that, pursuant to section 44 of the PUB Act, the PUB had the "flexibility to grant [Manitoba Hydro's] application in whole or part or to grant further or other relief 'in addition to or in substitution for that applied for'". Relying on *Coalition of Manitoba Motorcycle Groups Inc. v. Manitoba (Public Utilities Board)*, 1995 CarswellMan 433 (Man. C.A.) at para 25, it asserts that, when considering and granting relief, "[a]ll 'aspects of a rate (are) in issue'."

33 AMC agrees with the PUB that the *PUB Act*, the *Crow*n Act and the *Hydro Act* give the PUB authority to direct the creation of a new customer class.

Analysis

34 Section 2(5) of the PUB Act provides:

> **Application to Manitoba Hydro**
>
> **2(5)** Subject to Part 4 of [the *Crown Act*] and except for the purposes of conducting a public hearing in respect of an application made to the [PUB] under subsection 38(2) or 50(4) of [the] *Hydro Act*, this Act, other than subsection 83(4) and the regulations under that subsection, does not apply to Manitoba Hydro and the [PUB] has no jurisdiction or authority over Manitoba Hydro.

35 Regarding the prices to be fixed by Manitoba Hydro for the provision of power, section 39(2) of the Hydro Act states:

> **Fixing of price by corporation**

39(2) Subject to Part 4 of [the *Crown Act*] and to subsection (2.1), [Manitoba Hydro] may fix the prices to be charged for power supplied by [Manitoba Hydro].

36 Part 4 of the Crown Act contains sections 25(1)-25(3), which state:

Hydro and MPIC rates review

25(1) Despite any other Act or law, rates for services provided by Manitoba Hydro and the Manitoba Public Insurance Corporation shall be reviewed by The Public Utilities Board under [the *PUB*] *Act* and no change in rates for services shall be made and no new rates for services shall be introduced without the approval of The Public Utilities Board.

Definition: "rates for services"

25(2) For the purposes of this Part, **"rates for services"** means

(a) in the case of Manitoba Hydro, prices charged by that corporation with respect to the provision of power as defined in [the] *Hydro Act*; ...

. . .

Application of [PUB] Act

25(3) [The *PUB*] *Act* applies with any necessary changes to a review pursuant to this Part of rates for services.

37 The sections of the PUB Act which are relevant to whether the PUB has authority to create customer classes are sections 44(1), 77(a)-77(b) and 82(1)(a) and 82(1)(c). Those sections state:

Power to order partial or other relief

44(1) Upon any application to it, the [PUB] may make an order granting the whole or part only of the application or may grant such further or other relief in addition to or in substitution for that applied for, as fully and in all respects as if the application had been for such partial, further or other relief.

Orders as to utilities

77 The [PUB] may, by order in writing after notice to, and hearing of, the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls, charges, or schedules thereof, as well as commutation, mileage, and other special rates that shall be imposed, observed, and followed thereafter, by any owner of a public utility wherever the [PUB] determines that any existing individual rate, joint rate, roll, charge or schedule thereof or commutation, mileage, or other special rate is unjust, unreasonable, insufficient, or unjustly discriminatory or preferential;

(b) fix just and reasonable standards, *classifications*, regulations, practices, measurements, or service to be furnished, imposed, observed, and followed thereafter by any such owner;

Discriminatory rates

82(1) No owner of a public utility shall

(a) make, impose, or exact any unjust or unreasonable, unjustly discriminatory, or unduly preferential, individual or joint rate, commutation rate, mileage, or other special rate, toll, fare, charge, or schedule, for any product or service supplied or rendered by it within the province;

> (c) adopt or impose any unjust or unreasonable classification in the making, or as the basis, of any individual or joint rate, toll, fare, charge, or schedule for any product or service rendered by it within the province;
>
> [emphasis added]

38 Contrary to Manitoba Hydro's position, I am of the view that sections 77(b) and 82(1)(c) of the PUB Act do apply to a PUB review of its customer classifications. The limitation on the PUB's authority found in section 2(5) of the PUB Act specifies that it is subject to Part 4 of the Crown Act. Section 25(3) of the Crown Act specifically allows for the application of the PUB Act "with any necessary changes" to a review of the rates charged by Manitoba Hydro. I disagree with the suggestion made by Manitoba Hydro that section 25(3) of the Crown Act is limited to process only. There is nothing in section 25(3) that would limit its application to matters of procedure before the PUB.

39 The PUB is mandated to review rates on the basis of whether they are just and reasonable. Sections 77(b) and 82(1)(c) of the PUB Act clearly contemplate the necessity for just and reasonable rates *and* classifications.

40 In my view, the setting of customer classifications is an inherent part of the setting of rates. In *Coalition of Manitoba Motorcycle Groups*, Twaddle JA considered the breadth of section 44(1) of the PUB Act and its application to a decision made by the PUB to increase insurance rates in an amount higher than that requested by the Manitoba Public Insurance Corporation. He agreed that "if the [PUB] has discretion to set any rate that is fair and reasonable upon the evidence and in the public interest, then all aspects of the rates are 'in issue'" (at para 25). In my view, that statement is equally applicable in this case.

41 In summary, a purposive approach to the interpretation of the legislation supports the ability of the PUB pursuant to section 82(1)(c) of the PUB Act to review the classifications created by Manitoba Hydro to ensure that they are not unjust or unreasonable. Similarly, it has the authority to fix just and reasonable rates, charges and classifications. Nevertheless, as I next explain, the PUB must act within the statutory limits set out in the *Hydro Act* when exercising its jurisdiction.

Ground 2—Did the PUB Err in Its Understanding of the Uniform Rates Provision of the Hydro Act and the Regulatory Principle of Non-Discrimination?

Ground 3 — Did the PUB Err in Its Definition of Reserve?

Positions of the Parties

42 Manitoba Hydro argues that the creation of the on-reserve class breached sections 39(2.1) and 39(2.2) of the Hydro Act which require that the price charged for power supplied to a class of grid customers shall be the same throughout the province and that customers are not to be classified solely on the basis of the region in the province in which they are located or on the population density.

43 The PUB and AMC submit that the PUB did not err when it concluded that section 39 of the Hydro Act was not offended by the creation of the on-reserve class. They disagree with Manitoba Hydro's interpretation of the intent of the legislation and maintain that the on-reserve class is not based on a region in the province, as there are 63 different reserves throughout the province. The PUB further argues that the on-reserve class is not solely based on the region of the province, as it is defined on the basis of class members belonging to Manitoba First Nations, being residential customers and living on reserve.

Analysis

44 Section 39 of the Hydro Act governs the sale of power by Manitoba Hydro. Section 39(1) provides:

> **Price of power sold by corporation**
>
> **39(1)** The prices payable for power supplied by [Manitoba Hydro] shall be such as to return to it in full the cost to [Manitoba Hydro], of supplying the power, including

. . .

45 Sections 39(2.1) and 39(2.2) provide:

> **Equalization of rates**
>
> **39(2.1)** The rates charged for power supplied to a class of grid customers within the province shall be the same throughout the province.
>
> **Interpretation**
>
> **39(2.2)** For the purpose of subsection (2.1),
>
> > (a) grid customers are those who obtain power from [Manitoba Hydro's] main interconnected system for transmitting and distributing power in Manitoba; and
> >
> > (b) customers shall not be classified based <u>solely on the region of the province</u> in which they are located or on the population density of the area in which they are located.
>
> [emphasis added]

46 The ability of the PUB to review, approve and fix rates is constrained by the provisions of the *Hydro Act*.

47 A review of the legislative history of sections 39(2.1) and 39(2.2) evidences that those sections were enacted to equalize rates among residential customers. Prior to their enactment, Manitoba Hydro divided residential customers into three zones dependent on the density of the population and the number of metered services, and it calculated its rates for each zone based on the cost of service principle. As a result, rural or remote customers paid more for the provision of power supplied by Manitoba Hydro.

48 In 2001, *The* Manitoba Hydro Amendment Act (2), SM 2001, c 23, which enacted sections 39(2.1) and 39(2.2), came into force. During the second reading of Bill 27, The Manitoba Hydro Amendment Act *(2)*, 2nd reading, Manitoba, Legislative Assembly, *Debates and Proceedings (Hansard)*, 37-2, vol 51, No 38 (30 May 2001), online (pdf): *Legislative Assembly of Manitoba* < www.gov.mb.ca/legislature/hansard/37th_2nd/hansardp df/38.pdf> (date accessed 22 May 2020), the Hon Greg Selinger, then Minister charged with the administration of the *Hydro Act*, stated (at p 2505):

> **Mr. Selinger:** I am pleased to give second reading to this bill. As I mentioned in the first reading, this legislation will require Manitoba Hydro to charge customers connected to the provincial power grid the same rate for electricity service, regardless of where they live in Manitoba.
>
> Mr. Speaker, on December 5, 2000, the Speech from the Throne promised this single rate for residential hydro users.

49 That the government understood that the equalization of the cost for the provision of hydro was a government policy decision requiring legislative authority is evidenced by the comments of Minister Selinger in the Manitoba, Legislative Assembly, Standing Committee on Public Utilities and Natural Resources, *Committee Debates (Hansard)*, 37-2, vol 51, No 3 (18 June 2001), online (pdf): *Legislative Assembly of Manitoba* <www.gov.mb.ca/legislature/hansard/37th_2nd/hansardpdf/pu3.pdf> (date accessed 22 May 2020) (at pp 96, 98-99):

> **Mr. Selinger:** As we have discussed in the Legislature, it was the Government's decision to proceed by legislation for uniform rates, and that is because it is a change, not an adjustment to the existing rate structure. It is a change, a policy-driven change to the rates themselves, to go to a uniform or universal rate for all Manitobans.
>
> . . .

> **Mr. Selinger:** Once again, the uniform rates we are proposing which lower electricity rates for rural and northern customers are ones that were promised in an election. It is a change in policy. It is not an adjustment to an existing rate structure. A change in policy is the responsibility of the Government, and the Government is taking that responsibility in the Legislature and in this committee, presenting you with that information and proceeding on that basis. That is a completely legitimate role for government.
>
> . . .
>
> The structural change to go to a uniform rate is one that is driven by the Government who has the majority in the Legislature and has made that election commitment.
>
> [emphasis added]

50 In the context of this appeal, it is significant that the PUB itself has previously recognised that, while it may consider the creation of classes for the purposes of setting rates, it may only do so "provided that no geographic limitations are imposed on such a class" (Order No 73/15 at p 29).

51 I agree with Manitoba Hydro that, in enacting sections 39(2.1) and 39(2.2), the legislative intent was to equalize the price of power charged to residential customers in various regions of the province. I also agree with Manitoba Hydro's assertion that the reserves contemplated by the directive are "tract[s] of land" (as so defined in section 2(1) of the Indian Act, RSC 1985, c I-5) and that they are, in fact, specific geographic regions in the province.

52 At the hearing, this Court questioned whether persons who were not of First Nations descent, but who were living on a reserve, were eligible for the zero per cent increase benefit provided to the on-reserve class. The PUB argued that it intended that the on-reserve class would only apply to those customers that were of First Nations descent. It stated that, based on the record of the hearings before the PUB, it was apparent that its intent was for Manitoba Hydro to identify First Nations customers as those persons having treaty status. This was a troublesome submission for a number of reasons. To begin, there is no reference in the PUB's reasons to eligibility based on treaty status and, in my view, there is nothing in the reasons to support that interpretation. The directive was for Manitoba Hydro to "create a First Nations On-Reserve Residential customer class" (Order No 59/18 at p 266). In the absence of the PUB's oral submission, one would have assumed that Indigenous persons living on reserve without treaty status would also fall within the proposed class.

53 Although the PUB created the on-reserve class to address poverty concerns, treaty members who do not reside on reserve are not eligible, even if they are living in similar circumstances. Clearly, the defining circumstance for class membership is geographic location, not poverty or treaty status.

54 In my view, the PUB erred in law when it created an on-reserve class based solely on a geographic region of the province in which certain customers are located. Regardless of the considerations that the PUB factored into its decision, such as poverty and/or bill affordability, the result of the directive was the creation of a customer class that contravened section 39(2.2)(b) of the Hydro Act.

55 Before leaving this area, I would observe that the creation of a class restricted to persons to be identified by treaty status and the fixing of a rate for power supplied to that class may also contravene sections 82(1)(a) and 82(1)(c) of the PUB Act. Here, the PUB has created a class and a price for power supplied to that class that is lower than the price for the same power charged to similar ratepayers in the province. However well-intentioned, it cannot be just and reasonable for disadvantaged individuals on reserve to pay a lower price than other similarly disadvantaged individuals located on reserve or elsewhere in the province. Moreover, there is no indication that the PUB considered whether it would be just and reasonable for the remaining ratepayers in the province to subsidise the on-reserve class. All of the above underscores why initiatives to address broad social issues such as poverty should be left to the government.

Ground 4 — Did the PUB Err in Its Application of the Limited Class Rule?

Ground 5 — Did the PUB Err in Law in Intruding Into Social Policy?

Ground 6 — Did the PUB Err in Causing Manitoba Hydro to Expend Funds for Purposes of Poverty Reduction (Government Purposes)?

Positions of the Parties

56 Manitoba Hydro argues that its mandate is focussed on the provision of power adequate for the needs of the province in an economical and efficient manner. Relying on the reasons of the dissenting member of the PUB, Manitoba Hydro submits that the PUB exceeded its jurisdiction by making an order that purports to implement broad social policy, a role reserved to the provincial and federal governments.

57 It argues that section 43(3) of the Hydro Act prohibits the use of its funds for government purposes. In its view, the creation of the on-reserve class amounted to an attempt to alleviate poverty, which is a "Government purpose".

58 In support of its position that the PUB does not have the jurisdiction to implement broad social policy, Manitoba Hydro relies on the cases of *ENMAX Power Corp., Re*, 2004 CarswellAlta 2078 (Alta. E.U.B.) at paras 979-83 (Alberta Energy and Utilities Board found to be an unsuitable forum within which to address social issues or ratemaking on the basis of a customer's ability to pay); *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74 (N.S. C.A.) (*Dalhousie*) at paras 1, 40 (Nova Scotia Utility and Review Board had no jurisdiction to order reduced power rates based on the income level of the customer); and *British Columbia Hydro and Power Authority, Re*, 2017 CarswellBC 193 (B.C. Utilities Comm.) (British Columbia Utilities Commission finding that low-income rates unsupported by an economic or cost of service justification are unjust, unreasonable and unduly discriminatory).

59 Manitoba Hydro agrees that sections 25(4)(a)(viii) and 25(4)(a)(ix) of the *Crown Act* provide that the PUB may consider "compelling policy considerations" and "any other factors that the [PUB] considers relevant to the matter". However, it argues that the interpretation of those sections should be limited to the identified financial factors in sections 25(4)(a)(i)-25(4)(a)(vii). It further submits that sections 25(4)(a)(viii) and 25(4)(a)(ix) cannot be considered in isolation from the legislative scheme and the regulatory principle of cost of service on which rates are to be determined.

60 The PUB argues that it has jurisdiction to consider the issue of bill affordability, including ordering a program such as a "lower-income rate" in fulfilling its mandate to set just and reasonable hydro rates. In its view, while the government is better placed to introduce a bill affordability program, that does not mean that the PUB is prohibited from doing so.

61 In support of its position, the PUB relies on the decision of *Advocacy Centre for Tenants-Ontario v. Ontario (Energy Board)* (2008), 293 D.L.R. (4th) 684 (Ont. Div. Ct.) (*Advocacy Centre*). In that case, a majority of the Court held that the Ontario Energy Board (OEB) had the jurisdiction to take into account customers' ability to pay in setting rates.

62 In the PUB's view, its jurisdiction is more closely aligned to the statutory framework in Ontario than that considered by the Nova Scotia Court of Appeal in *Dalhousie*.

63 The PUB submits that, to read sections 25(4)(a)(viii) and 25(4)(a)(ix) as being limited to the financial factors set out in sections 25(4)(a)(i)-25(4)(a)(vii), is contrary to the legislative intent that the PUB fix just and reasonable rates in the general public interest through balancing the interest of Manitoba Hydro's ratepayers and the financial health of the utility. It argues that the *Crown Act* goes further than the *Hydro Act* in providing for the consideration of factors beyond those listed in sections 25(4)(a)(i)-25(4)(a)(vii).

64 Finally, the PUB argues that the directive does not direct the use of hydro funds for government purposes as, collectively, ratepayers are paying for the provision of power necessary for Manitoba Hydro's approved revenue requirement.

65 While agreeing that cost of service must be a critical factor in the setting of rates, CAC Manitoba argues that the PUB can consider compelling social policy, not limited to financial, considerations.

66 AMC emphasises that the PUB did not err in its consideration of bill affordability as well as public policy in creating the on-reserve class. It argues that the directive is consistent with the *PTRA*.

Analysis

67 The main issue engaged by these three grounds of appeal concerns the interplay between sections 2 and 43(3) of the Hydro Act, as well as factors that the PUB may take into consideration in reaching a decision regarding just and reasonable rates for services provided by Manitoba Hydro pursuant to section 25(4)(a) of the Crown Act.

68 Manitoba Hydro is empowered to carry out the purposes and objects specified in section 2 of the Hydro Act:

> **Purposes and objects of Act**
>
> **2** The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are
>
> > (a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and
> >
> > (b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.

69 Regarding the allocation and use of Manitoba Hydro's funds, section 43(3) of the Hydro Act provides:

> **Funds of government and corporation not to be mixed**
>
> **43(3)** <u>Except as specifically provided in this Act, the funds of the corporation shall not be employed for the purposes of the government or any agency of the government</u> as that expression is defined in *The Civil Service Act*, [CCSM c C110] <u>other than the corporation</u>, and the funds of the government shall not be employed for the purposes of the corporation except as advances to the corporation by the government by way of loan or as a result of a guarantee by the government of indebtedness of, or assumed by, the corporation or liability for the repayment of which is an obligation of the corporation.
>
> [emphasis added]

70 Section 25(4)(a) of the Crown Act provides the factors that may be considered by the PUB in determining rates for services. It states:

> **Factors to be considered, hearings**
>
> **25(4)** In reaching a decision pursuant to this Part, The [PUB] may
>
> > (a) take into consideration
> >
> > > (i) the amount required to provide sufficient funds to cover operating, maintenance and administration expenses of the corporation,
> > >
> > > (ii) interest and expenses on debt incurred for the purposes of the corporation by the government,
> > >
> > > (iii) interest on debt incurred by the corporation,
> > >
> > > (iv) reserves for replacement, renewal and obsolescence of works of the corporation,
> > >
> > > (v) any other reserves that are necessary for the maintenance, operation, and replacement of works of the corporation,

(vi) liabilities of the corporation for pension benefits and other employee benefit programs,

(vii) any other payments that are required to be made out of the revenue of the corporation,

(viii) <u>any compelling policy considerations that the board considers relevant to the matter</u>, and

(ix) <u>any other factors that the Board considers relevant to the matter</u>;

[emphasis added]

71 It is interesting to note that the French language version of section 25(4)(a)(viii) states the PUB may consider "des considérations de principe importantes qu'elle estime pertinentes à l'affaire". In my view, the French translation permits consideration of "important policy considerations", which could arguably influence the interpretation of the phrase "compelling policy considerations" found in the English version. However, as the matter was not argued before us, I will not comment further on this observation.

72 While the PUB has broad authority to make orders approving or setting rates for Manitoba Hydro that are not unjust, unreasonable or discriminatory, the PUB is clearly constrained by the prohibition contained in section 43(3) of the Hydro Act.

73 Historically, the PUB was of the view that it did not have the jurisdiction to consider ability to pay as a factor in approving costs. For example, in Order No 17/04 [February 6, 2004Doc. 17/04 (Man. P.U.C.)], the PUB considered an application by Manitoba Hydro to increase certain rates for electric service for four remote communities that were served by diesel generation. The application proposed that all First Nations accounts, regardless of the source and level of funding, be subject to the government rate, including the government surcharge. After hearing evidence regarding inability to pay from Manitoba Keewatinook Ininew Okimowin (MKO), two First Nations Chiefs as well as other Manitoba Hydro customers affected by the application, the PUB declined to exempt First Nations from paying the government surcharge. It stated (at p 31):

> The [PUB] remains extremely sensitive to the rising costs of living in Northern Manitoba, and the ability to pay issue. However, the [PUB] also has a duty and responsibility to [Manitoba] Hydro and to the large population of all of [Manitoba] Hydro's customers to set rates for diesel communities that are just and reasonable, within the mandate of the [PUB] in applying the principles of rate regulation. It is the [PUB]'s view that the ability to pay issue is one that lies outside of the regulatory arena, and lies more appropriately within the Provincial and Federal Social Policy area. [Manitoba] Hydro grid customers presently subsidize electricity rates in remote diesel communities to a significant degree. The [PUB] refers to the Governments of Canada and Manitoba the need for improved social policy to address the ability of people living in remote northern communities to pay for essential services. It is not within the mandate of [the PUB] to use utility rates to effect social policy.

74 The above statement is consistent with the decision of the majority of the OEB in Enbridge Gas Distribution Inc., Re [2007 CarswellOnt 12191 (Ont. Energy Bd.)] (26 April 2007), EB-2006-0034, online (pdf): *Ontario Energy Board* <www.oeb.ca/documents/ cases/EB-2006-0034/decision_egd_rate_affordability_20070426.pdf> (date accessed 26 May 2020). In that decision, the OEB held that the Ontario Energy Board Act, 1998, SO 1998, c 15, Schedule B (the OEB Act) did not provide it with either explicit or implicit jurisdiction to order the implementation of a rate class based on rate affordability for low income customers.

75 On appeal, the decision of the OEB was overturned by a majority of the Court in *Advocacy Centre*. In that case, the majority determined that, while the traditional "cost of service" approach was the "root principle underlying the determination of rates" (at para 52), the OEB was authorised by the OEB Act to take "into account income levels in pricing to achieve the delivery of affordable energy to low income consumers" (at para 55). In reaching this conclusion, the majority considered section 36 of the OEB Act (at para 15):

> Section 36 of the [*OEB*] Act confers the [OEB's] jurisdiction:

> **36.**(1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.
>
> . . .
>
> (2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.
>
> (3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.
>
> [emphasis added]

76 In interpreting the term "just and reasonable rates", the majority considered *Hansard*, stating (at paras 19-20):

> The phrase "approving or fixing just and reasonable rates" in the present s. 36(2) was first introduced by s. 17(1) of Bill 38, *An Act to Establish the Ontario Energy Board*, 1st Sess., 26th Leg., Ontario, 1960 by the then Minister of Energy Resources, the Hon. Robert Macaulay. He outlined for the Legislature the philosophy underlying rate setting (*Legislature of Ontario Debates*, 9 (8 February 1960) at 199 (Hon. Macaulay)):
>
> > First, why are there rate controls? There are rate controls because, in effect, the distribution of natural gas is a monopoly, a public utility. Secondly...it is fair that whatever rate is charged should be one designated, not only in the interests of the consumer, but also in the interests of the distributor... [O]ne really should have in mind 3 basic objectives: First, the rate should be low enough to secure to the user a fair and just rate. Second, the rate should be adequate to pay for good service and replacement and retirement of the used portion of the assets. Third, it should be high enough to attract a sufficient return on capital....
>
> He went on to explain the purpose of the Government's policy (at 205):
>
> > [F]irst, to protect the consumer, and to see that he pays a fair and just rate, not more or less, and that is competitive with other fuels. Second, to make sure the rate is sufficient to provide adequate service, replacements and safety for the company providing the service. Third, it is that the company should be able to charge a rate which is sufficient to attract the necessary capital to expand.

77 The majority observed that section 36 replaced previous legislation, which limited the phrase "just and reasonable rates" to the traditional cost of service analysis (at para 23).

78 Next, it considered section 36 in conjunction with objective 2 under section 2 of the OEB Act. That objective was stated to be "[t]o protect the interests of consumers with respect to prices and the reliability and quality of gas service" (at para 33). It concluded (at para 61):

> [T]he [OEB] 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 [OEB] 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.

79 After the decision in *Advocacy Centre*, the PUB determined in Order No 116/08 [July 29, 2008Doc. 116/08 (Man. P.U.C.)] that "Manitoba and Ontario rate setting jurisdictions are similarly broad" (at p 230) and that it had jurisdiction to order the implementation of a rate affordability program. Since that time, the PUB has reasserted its jurisdiction to consider bill affordability. See, for example, Order No 73/15 [July 24, 2015Doc. 73/15 (Man. P.U.C.)].

80 In its decision in the present case, the PUB reasoned that the jurisdiction to implement a bill affordability program provided it with the authority to make the directive that is the subject of this appeal.

81 I agree with the PUB that it is entitled to consider social policy and any other factors it considers relevant in fulfilling its mandate. I see no reason to limit the interpretation of sections 25(4)(a)(viii) and 25(4)(a)(ix) to the financial considerations found in sections 25(4)(a)(i) to 25(4)(a)(vii). There is nothing in section 25(4)(a) to suggest such an interpretation.

82 Further, the interpretation suggested by Manitoba Hydro is not supported by *Hansard*. In the second reading of Bill 37, The Crown Corporations Public Review and Accountability and Consequential Amendments Act, 2nd reading, Manitoba, Legislative Assembly, *Debates and Proceedings (Hansard)*, 34-1, vol 37, No 72 (4 November 1988), online (pdf): *Legislative Assembly of Manitoba* <www.gov.mb.ca/legislature/hansard/34th_1st/hansardpdf/72.pdf> (as repealed by the *Crown Act* at section 39) the Hon Clayton Manness, then Minister responsible for Crown corporations, stated (at p 2806):

> Factors to be considered, Mr. Speaker, we have given the [PUB] some direction as to what factors are to be considered. Not only are they to look at financial considerations but, if there are compelling social factors that can be presented in an argument, we have mandated the [PUB] to look at those, to take those into account before they reach their decision.

83 Bill affordability is an issue of social policy. It forms part of the PUB's concerns when dealing with a rate application, described by Michel Monnin JA in *Consumers' Assn. of Canada (Manitoba) Inc. v. Manitoba Hydro Electric Board*, 2005 MBCA 55 (Man. C.A.), as "the interests of the utility's ratepayers, and the financial health of the utility" (at para 65).

84 In addition, although not determinative to the PUB's decision, I am not persuaded that the PUB erred in considering the *PTRA* and the social policy underlying that legislation in reaching its conclusion.

85 Nevertheless, the ability to consider factors such as social policy and bill affordability in approving and fixing rates for service does not equate to the authority to direct the creation of customer classifications implementing broader social policy aimed at poverty reduction and which have the effect of redistributing Manitoba Hydro's funds and revenues to alleviate such conditions.

86 A plain and purposive reading of section 43(3) of the Hydro Act evidences that funds and revenue of Manitoba Hydro are not to be used by the government to serve any purpose other than that of Manitoba Hydro.

87 I agree with the dissenting member of the PUB that the directive constitutes "a realm that is reserved for the federal and provincial governments" (Order No 59/18 at p 235; see also, for example, section 91(24) of the Constitution Act, 1982) as well as the impermissible creation and implementation of social policy. This is also consistent with the remarks made by Minister Selinger preceding the enactment of sections 39(2.1) and 39(2.2) of the Hydro Act referred to earlier in these reasons.

88 Without explicitly stating that the PUB has no jurisdiction to implement broad social policy, this Court has previously expressed reservations about the jurisdiction of the PUB to make orders that would normally fall within the purview of government. For example, in *Cash Store Financial Services Inc., Re*, 2009 MBCA 1 (Man. C.A.), MacInnes JA granted the applicant, a payday loan business, leave to appeal a decision from a PUB order which set maximum charges with respect to payday loans (see para 1). He found that it was at least arguable that the PUB overstepped its jurisdiction in expressing its "philosophical views" (at para 49) against the morality of payday loans (see also paras 46-47). Of note, the appeal in that case was discontinued prior to being heard by this Court.

89 In my view, the PUB erred in applying *Advocacy Centre* in determining that it had the authority to order the directive. That case is distinguishable. In *Advocacy Centre*, the majority of the Court did not consider legislation similar to section 43(3) of the Hydro Act prohibiting the use of the utility's funds or revenue for government purposes. Furthermore, the powers conferred on the PUB are not as broad or as expansive as those conveyed by sections 36(2) and 36(3) of the OEB Act.

90 I am in agreement with the dissenting reasons of Swinton J in *Advocacy Centre*. She recognised that, historically, principles governing public utilities mandated equal treatment of all customers respecting rates. She stated (at paras 92, 94-96):

> 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.
>
> 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, s.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.
>
> 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.
>
> 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. ...

91 In this case, similar problems arise. The on-reserve class creates anomalies between those who are similarly situated. Persons who are not of Indigenous descent or who do not have treaty status, but who live on a "First Nations" reserve, may or may not be eligible for the benefit, while those living in similar circumstances, but not on reserve, are not eligible.

92 As earlier stated, the PUB assumed that Manitoba Hydro would remain whole on the basis that "collectively ratepayers are paying for the provision of power at the level necessary for [Manitoba Hydro's] approved revenue requirement." This means that all other customer classes must pay more for the provision of power to account for the shortfall resulting from the zero per cent increase to prices charged to customers in the on-reserve class.

93 Furthermore, the evidence in this case demonstrates that the federal government pays for the hydro costs of persons living on reserve who are in receipt of employment income assistance. Thus, the directive may actually, in some cases, amount to a subsidy to the federal government and not provide relief to ratepayers in the on-reserve class.

94 In Order No 59/18, the PUB acknowledged that the directive created anomalies, but felt that these were better left to an elected government (at p 29):

> The anomalies that result from this measure are best addressed by a more wide-reaching government bill affordability program. The [PUB] envisions that, with the introduction of a comprehensive government bill affordability program, the [on-reserve] class and lower rate built into the 2018/19 Test Year may no longer be required.

95 It also noted that the Government of Manitoba already had a social program infrastructure in place to address broader social policy issues and programs (at p 229):

> There is an important role for governments in advancing bill affordability for all Manitobans. The [PUB] unanimously recommends that the provincial government introduce a comprehensive bill affordability program run by a government department to address energy poverty issues faced by Manitobans throughout the province. The [PUB] heard evidence that

there is a long-standing need to address this issue and the government is best situated to do so in a comprehensive fashion. The provincial government has social program infrastructure already in place.

96 Finally, accounting for the fact that the legislation in each of the following provinces contains distinct wording, I would note that Swinton J's position is fundamentally consistent with the decisions of the Nova Scotia Court of Appeal in *Dalhousie* at para 33; the Alberta Energy and Utilities Board's decision in *ENMAX* at paras 979-83; and *British Columbia Old Age Pensioners' Organization v. British Columbia Utilities Commission*, 2017 BCCA 400 (B.C. C.A.) at para 38, leave to appeal to BC CA refused.

97 Therefore, based on the above, it is my view that the PUB exceeded its jurisdiction and that the directive is in contravention of section 43(3) of the Hydro Act.

Decision

98 In accordance with section 58(5) of the PUB Act, which requires this Court to certify its opinion to the PUB, I am of the opinion that the PUB exceeded its jurisdiction by making a directive that breached sections 39(2.2) and 43(3) of the Hydro Act.

99 For all of the above reasons, I would grant the appeal and set aside the directive.

100 Section 58(8) of the PUB Act exempts the PUB from an award of costs. In the circumstances, I would make no order of costs against the interveners.

***William J. Burnett J.A.*:**

I agree:

***Janice L. leMaistre J.A.*:**

I agree:

Appeal allowed.