THE BOARD of COMMISSIONERS of PUBLIC UTILITIES

NEWFOUNDLAND and LABRADOR HYDRO

2026 General Rate Application (Based on a 2027 Test Year)

Revenue Requirement & Regulatory Accounting Evidence

Prepared By

Darren Rainkie

On Behalf of

The Consumer Advocate

November 2, 2026

Table of Contents

1.0 Executive Summary: Robust & Proactive Regulatory Oversight is Critical in an Era of Unprecedented Volatility, Uncertainty, Complexity and Ambiguity 5

1.1 It is Recommended that the PUB Direct NLH to File its Next Comprehensive GRA in 2028 and that this GRA Include Both a 2029 Test Year and 2030 Test Year and Forecasts to 2033 5

NLH's Position on Next GRA (2030) is Compliance Based & Focused on Administrative Efficiency 5

Circumstances Suggest Robust & Proactive PUB Oversight is Critical in this Environment 5

Recommendation to the PUB to Direct a Comprehensive GRA be Filed by NLH in 2028 6

1.2 There are Recommended Adjustments & Outstanding Concerns Related to NLH's 2027 Test Year Revenue Requirement Proposals 6

Operating Cost Adjustment Recommendations 6

Depreciation & Accretion Filing Recommendations for the Next GRA 7

Rate Base & Return on Rate Base – Observations, Conclusions & Recommendations 7

1.3 There are Recommended Adjustments & Outstanding Concerns Related to NLH's Update of Its Intercompany Transactions Costing Guidelines 7

Recommended Acceptance of Three ITCG Methodology Changes for the 2027 Test Year 7

Recommended Adjustment to the Allocation of IT Costs for the 2027 Test Year 8

Outstanding ITCG Issue for Further Consideration at this GRA 8

1.4 There are Alternative Recommendations with Respect to NLH's Regulatory Deferral Account Proposals 8

Recommended Acceptance of NLH's RDA Proposals 8

Alternative Recommendations with Respect to NLH's RDA Proposals 9

2.0 This Evidence Evaluates NLH's Position on the Timing of Its Next GRA and 2027 Test Year Revenue Requirement Proposals and Regulatory Accounting Proposals 10

2.1 NLH is Requesting Approval of a Targeted 2.25% Rate Increase Effective July 1, 2027 for Domestic Customer on the Island Interconnected System Consistent with the Rate Mitigation Plan 10

2.2 Mr. Rainkie has 36 Years of Multi-Faceted Experience in Public Utility Leadership, Rate-Regulation and Financial Management & Acknowledges His Duties to the PUB 11

Duties to the PUB and Independence 13

2.3 This Evidence Evaluates NLH's Position on the Timing of NLH's Next GRA and 2027 Test Year Revenue Requirement Proposals and Regulatory Accounting Proposals 13

3.0 Robust & Proactive Regulatory Oversight is Critical in an Era of Unprecedented Volatility, Uncertainty, Complexity and Ambiguity and Associated Rate Pressures 15

3.1 NLH's Approach to Regulatory Oversight by the PUB is Focused Mainly on Historical Test-Years, Compliance-Based Regulation & Administrative Efficiency..... 16

3.2 The Energy Transition is Inherently an Era of Unprecedented Volatility, Uncertainty, Complexity and Ambiguity for Electric Utilities such as NLH..... 17

3.3 There is Significant Concerns with respect to the Uncertainty and Sustainability of a Rate Mitigation Plan in 2031 and Beyond..... 21

3.4 There are $188 Million of Additional Revenue Requirement Offsets in the 2027 Test Year Primarily Related to In-Service of Muskrat Falls Assets that are Not Expected to Reoccur in Future Test Years 24

3.5 There are Other Future Cost and Rate Pressures Associated with Increased Levels of Capital Expenditures, Escalation of Operating Costs and Build Up of Regulatory Deferral Accounts..... 26

3.6 Rate Mitigation Uncertainty and Other Costs Pressures Directionally Point to Significant Revenue Requirement and Rate Pressures to 2030 and Beyond..... 28

3.7 Robust & Proactive Regulatory Oversight by the PUB is Critical in an Era of Unprecedented Volatility, Uncertainty, Complexity and Ambiguity and Associated Rate Pressures for NLH 31

3.8 It is Recommended that the PUB Direct NLH to File its Next Comprehensive GRA in 2028 and that this GRA Include Both a 2029 Test Year and 2030 Test Year and Forecasts to 2032 32

4.0 There are Recommended Adjustments & Outstanding Concerns Related to NLH's 2027 Test Year Revenue Requirement Proposals..... 34

4.1 NLH's Operating Cost Growth Over the 6 Year Period between 2019 and 2025 Has Been In Line with the Consumers Price Index Increase of 18% or 2.8% Per Year..... 35

4.2 It is Recommended That the PUB Adjust NLH's Operating Cost Productivity Adjustment from $4 Million to $5 Million for Cost Escalation Between the 2019 Test Year and 2027 Test Year 38

4.3 It is Recommended That the PUB Adjust NLH's Vacancy Allowance from $6 Million to $7 Million to Recognize NLH's Recent Actual Vacancy Rate Experience 41

4.4 It is Recommended That NLH Be Directed to File Evidence to Bridge Between Summary Tables of Depreciation & Accretion and Comprehensive Depreciation Studies at Future GRAs 42

4.5 The Calculation of the $115 Million of Working Capital Allowance Related to Muskrat Falls and Included in the Proposed 2027 Test Year Rate Base is Reasonable 45

4.6 It Would Be Beneficial if the Appropriate Regulatory Treatment of the $9 Million of Interest Cost of Service Exclusions is Confirmed During the Up Coming Oral Hearing 47

4.7 It is Recommended That NLH is Directed to File Its Debt Management Strategy and Guidelines for the Use of Variable-Rate Debt with the PUB at the Next GRA 49

5.0 There is a Recommended Adjustment and Outstanding Concerns Related to NLH's Update of Its Intercompany Transactions Costing Guidelines (ITCG) 52

5.1 NLH's Revised Intercompany Transactions Costing Guidelines (ITCG) Allocate Over $34 Million of Shared Service Costs & Have Not Been Reviewed by the PUB Since the NLH 2013 GRA 53

5.2 The Prudency of the Underlying Shared Service Cost Allocations is a Distinct Issue from the Appropriateness of the ITCG Allocation Methodologies 54

5.3 Transitioning to a One-Step Allocation Approach & Removal of Administrative Business Unit Components from Allocator Calculations are Reasonable and Should be Approved by the PUB 55

Transition from a Partial Two-Step Allocation Approach to a One-Step Allocation Approach 55

Removal of Administrative Business Unit Components from Allocator Calculations 56

These Two ITCG Methodology Changes are Reasonable 56

5.4 It is Recommended That the PUB Direct NLH to Revisit the Merits of a 3-Factor Hybrid Allocator to Include Revenue at the Next GRA when Churchill Falls Renegotiations are Complete 58

NLH's Proposal to Transition to a 2-Factor Hybrid Allocator is a Directional Improvement 60

Potential Inclusion of Revenue in a 3-Factor Composite Allocator 60

Recommendations on the 2-Factor Hybrid Allocator for the 2027 Test Year 61

5.5 It is Recommended That the PUB Approve a Cost Allocator for IT Costs that is 50% Weighted to FTEs and 50% Weighted to the Proposed NLH Hybrid Allocator to Improve Cost Causation 61

NLH Proposes to Allocate IT Cost Pools 57% to Regulated & 43% to Non-Regulated Operations 61

Comparator Utilities Use Varied Cost Allocators to Allocate IT Costs 62

Assessment of an Alternative Cost Allocator for Allocation of IT Costs 62

Allocation of IT Shared Service Costs is an Outstanding Issue in this GRA 63

A Composite Allocator is Recommended to Allocate the NLH Three IT Cost Pools 64

6.0 There are Alternative Recommendations with Respect to NLH's Regulatory Deferral Account Proposals 66

6.1 This Section of the Evidence Evaluates & Makes Recommendations on NLH's Regulatory Deferral Account (RDA) Proposals that Impact the 2027 Test Year Revenue Requirements 67

6.2 It is Recommended that the Business Systems Transformation Program Deferral Account Be Amortized Over 10-Years which Would Reduce 2027 Test Year Amortization by $0.3 Million 67

6.3 It is Recommended that the Phase Two Hearing Costs Deferral Account Be Amortized Over Two Years which Would Increase 2027 Test Year Amortization by $0.6 Million 68

6.4 It is Recommended that the PUB Approve a Five Year Amortization Period for the Reliability & Resource Adequacy Study Review Deferral Account which Would Increase 2027 Test Year Amortization by $0.4 Million 69

6.5 It is Recommended that the PUB Approve Amortization of the Muskrat Falls PPA Sustaining Capital Deferral Account Using Composite Depreciation Rates & Inclusion in Rate Base 70

6.6 It is Recommended that the PUB Approve a Two Year Amortization Period for the External GRA Hearing Costs Deferral Account which Would Increase 2027 Test Year Amortization by $0.4 Million 72

6.7 It is Recommended that the Recovery Period of the Holyrood TGS Accelerated Depreciation Deferral Account be Set at a Future GRA When Information on the Retirement Date is Available 72

PUB Directed Report on the Activity and Operation of the Holyrood TGS RDA Since the Last GRA 73

Holyrood TGS RDA Accelerated Depreciation Scenario 75

Recommendations on the Holyrood TGS RDA 76

6.8 It is Recommended that the PUB Approve Financing Costs at the Short-Term Borrowing Rate for the Long-Term Supply Cost Variance Deferral Account 76

Summary of Request for Information Process with respect to the LT SCVDA 77

Analysis & Recommendations on the Creation & Disposition of the LTSCVDA 78

Analysis & Recommendations on Financing Costs for the LTSCVDA 79

1.0 Executive Summary: Robust & Proactive Regulatory Oversight is Critical in an Era of Unprecedented Volatility, Uncertainty, Complexity and Ambiguity

Newfoundland and Labrador Hydro's (NLH) 2026 General Rate Application (GRA) to the Board of Commissioners of Public Utilities (PUB) is based on a 2027 Test Year and incorporates the Muskrat Falls Supply Costs within the proposed revenue requirement for the first time since the Muskrat Falls Assets were commissioned.

NLH's 2027 Test Year revenue requirement has been mitigated to approximately $798 million through the application of the Government's Rate Mitigation Plan, with NLH's portion of Domestic customer annual rate increases on the Island Interconnected System being limited to the 2.25% targeted in the Rate Mitigation Plan.

The purpose and scope of this Evidence is to evaluate and make recommendations related to NLH's position on the timing of its next GRA and NLH's 2027 Test Year revenue requirement proposals, regulatory accounting proposals and update of its intercompany transactions costing guidelines.

The collective circumstances surrounding this GRA suggest an approach to the PUB regulatory oversight of NLH on a go-forward basis that is robust and proactive in an environment where the stakes are high for ratepayers and stakeholders - considering unprecedented volatility, uncertainty, complexity and ambiguity in the energy sector and NLH's operating environment as well as significant cost and rate pressures.

1.1 It is Recommended that the PUB Direct NLH to File its Next Comprehensive GRA in 2028 and that this GRA Include Both a 2029 Test Year and 2030 Test Year and Forecasts to 2033

NLH's position that it file its next comprehensive GRA no earlier than 2030 (2031 Test Year) was evaluated for reasonability based on NLH's operating environment and expected rate pressures.

NLH's Position on Next GRA (2030) is Compliance Based & Focused on Administrative Efficiency

NLH's position is that rates for the next three test years (2028 to 2030) be established through annual rate adjustment applications and that it will not file a comprehensive GRA with the PUB until 2030 (2031 Test Year) at the earliest (minimum of a four year interval until the next GRA). This position is a compliance based approach, focused on historic test-years and administrative efficiency and is risky given the current environment and build up of rate pressures in the next four years.

Circumstances Suggest Robust & Proactive PUB Oversight is Critical in this Environment

There is unprecedented volatility, uncertainty, complexity and ambiguity (VUCA) in NLH's business, operational and financial environment associated with the energy transition, the expiry of the Rate Mitigation Plan in 2030 and the recent signing of a framework agreement between

NLH and Hydro-Quebec related to Churchill Falls. Future rate mitigation uncertainty and other cost pressures related to capital expenditures, operating costs and regulatory deferrals, directionally point to significant revenue requirement and rate pressures to 2030 and beyond.

These circumstances suggest that **PUB regulatory oversight** of NLH on a go-forward basis needs to be robust, taking a macro-level (top-down) view of the electricity system through proactive policy making, with the primary focus on regulatory effectiveness and protecting the public interest.

Recommendation to the PUB to Direct a Comprehensive GRA be Filed by NLH in 2028

It is recommended that the PUB direct NLH to file its **next comprehensive GRA** in 2028 to include both 2029 and 2030 Test Years and file a medium-term financial forecast of at least three additional forecast years (2031, 2032 and 2033) for a total of five years of forecasts (2029 to 2033). This approach ensures the continued effectiveness of the PUB's regulatory oversight, allows for timely regulatory review of significant capital expenditures, other rate pressures and regulatory deferral accounts, while balancing considerations of regulatory efficiency.

It is also recommended that the PUB direct NLH to file **strategically oriented documents** in the next comprehensive GRA, to strengthen regulatory oversight and provide critical context of how strategic direction, aspirations, strategies and risk tolerances shape utility plans, revenues and cost estimates that form the basis of GRA filings and rates. These strategically oriented documents include: (i) strategic plan/overarching business strategy, (ii) risk management report and risk tolerances, (iii) asset management maturity and strategic asset management plan, (iv) debt management strategy and (v) artificial intelligence strategy.

1.2 There are Recommended Adjustments & Outstanding Concerns Related to NLH's 2027 Test Year Revenue Requirement Proposals

NLH's 2027 Test Year revenue requirement proposals were evaluated, focusing on issues related to operating costs, depreciation & accretion and return on rate base.

Operating Cost Adjustment Recommendations

NLH's assertion that its 2027 Test Year operating costs are forecast to be approximately 10% lower than the 2019 Test Year forecast in real dollars was evaluated with the analysis indicating that the growth in NLH's normalized operating costs between 2019 actual and 2025 actual of 18% or 2.8% per year was consistent with the growth in the Consumer Price Index. Recommendations to the PUB with respect to the 2027 Test Year operating costs are:

1. That the proposed $4 million **productivity allowance** be increased by $1 million to $5 million for the 2027 Test Year, considering the 23% escalation of costs since the last GRA and the additional opportunities to obtain efficiencies and productivity resulting from fast advancing technology and artificial intelligence; and

2. That the proposed $6 million **vacancy allowance** be increased by $1 million to $7 million for the 2027 Test Year, considering the most recent actual vacancy factor experienced by NLH in 2025.

Depreciation & Accretion Filing Recommendations for the Next GRA

It is recommended that the PUB direct NLH to provide supplemental evidence to support material changes to **depreciation** methodologies and depreciation expense and to bridge the gap between summary tables in the GRA filing and large technical depreciation studies when such studies are filed at future GRAs.

Rate Base & Return on Rate Base – Observations, Conclusions & Recommendations

With respect to **rate base** and **return on rate base**, observations, conclusions and recommendations are:

1. The $115 million proposed **Muskrat Falls working capital allowance** is reasonable for rate-setting purposes;
2. It would be beneficial to confirm the appropriate regulatory treatment of the $9 million of **interest cost of service exclusions** during the upcoming oral GRA hearing; and
3. That the PUB direct NLH to file its **debt management strategy** and policies/guidelines for the use of variable-rate short-term debt and variable-rate long-term debt at the next GRA, considering growing levels of debt at NLH, to ensure the prudency of NLH's financing strategies and to appropriately balance the benefits and risks of variable-rate debt on behalf of ratepayers.

1.3 There are Recommended Adjustments & Outstanding Concerns Related to NLH's Update of Its Intercompany Transactions Costing Guidelines

NLH updated and made proposed changes to its Intercompany Transactions Costing Guidelines (ITCG) that are used to allocate over $34 million of shared service costs between its regulated operations and non-regulated operations. The updates and proposed changes primarily result from the passage of time and a corporate reorganization. The last comprehensive review of the ITCG by the PUB occurred in the 2013 GRA.

Recommended Acceptance of Three ITCG Methodology Changes for the 2027 Test Year

NLH is proposing **three methodological changes to the ITCG**, which are evaluated as being reasonable and recommended to the PUB for acceptance for the purpose of setting rates for the 2027 Test Year:

1. Two changes to (i) transition to a **one-step allocation approach** in order to allocate administrative business unit costs and (ii) to **remove administrative business unit components** from allocator calculations. These proposed changes are practical, remove unnecessary complexity/false precision and improve the administrative simplicity, transparency and traceability of the allocation of shared service costs; and
2. A change to introduce a **2-factor hybrid allocator** (50% equal weightings to gross property, plant & equipment and operating & maintenance costs) to allocate executive, corporate secretary, communications and safety, health & environmental shared service costs. This proposed change is a directional improvement as these costs are most appropriately allocated using composite allocators that reflect the size, scale, scope and complexity of the operating units of NLH.

However, it is also recommended that the PUB direct NLH to re-evaluate the inclusion of revenue and potential development of a **3-factor composite allocator** to allocate these governance costs and report on this re-evaluation at its next GRA.

Recommended Adjustment to the Allocation of IT Costs for the 2027 Test Year

It is recommended that the PUB approve a **cost allocator for IT costs** that is weighted (i) 50% to FTEs and (ii) 50% to NLH's proposed 2-part hybrid allocator - to improve cost causation related to the diverse range of NLH's IT costs and simplify the allocations. This recommendation would reduce the proportion of shared service IT costs allocated to regulated operations to 44% (from 57% based solely on average users as proposed by NLH) and reduce operating costs by $2.6 million for the 2027 Test Year.

Outstanding ITCG Issue for Further Consideration at this GRA

There is an outstanding issue in this GRA regarding the **prudency** of net administration fees allocated from non-regulated operations as the PUB assesses both the prudency and necessity of the underlying shared service costs in addition to the appropriateness of the shared service allocation framework.

1.4 There are Alternative Recommendations with Respect to NLH's Regulatory Deferral Account Proposals

NLH's 2027 Test Year regulatory deferral account (RDA) proposals were evaluated, with areas of recommended acceptance and alternative recommendations outlined below.

Recommended Acceptance of NLH's RDA Proposals

Recommendations for PUB acceptance of NLH's RDA proposals, are summarized as follows:

1. Approval of NLH's proposals to amortize the balance in the **Muskrat Falls Sustaining Capital RDA** based on the composite depreciation rates of the Muskrat Falls Assets and include this RDA in rate base. It is also recommended that the PUB continue to scrutinize these sustaining capital expenditures in future GRAs given their unique regulatory treatment and annual variability; and
2. Acceptance of NLH's position that the **Holyrood TGS Accelerated Depreciation RDA** recovery period will not be determined in the current GRA proceeding. It is also recommended that the recovery period be determined at a future comprehensive GRA proceeding and not at a separate standalone regulatory proceeding.

Alternative Recommendations with Respect to NLH's RDA Proposals

Alternative RDA recommendations to the PUB related to NLH's proposals, are summarized as follows:

1. Approval of an amortization period of 10-years (versus eight-years proposed by NLH) for the **Business Systems Transformation Program RDA**, considering the size of the deferral, the nature of the deferred costs and plans for continued service. This recommendation would decrease 2027 Test Year amortization by $0.3 million;
2. Approval of an amortization period of two-years (versus eight-years proposed by NLH) for the **Phase Two Hearing Costs RDA**, considering the smaller size of the deferral and the long passage of time since the associated regulatory proceeding concluded. This recommendation would increase 2027 Test Year amortization by $0.6 million;
3. Approval of an amortization period of five-years (versus eight-years proposed by NLH) for the **Reliability & Resource Adequacy Study Review RDA**, considering the recency of additions to the RRA Study RDA and the larger balance in the account. This recommendation would increase the proposed 2027 Test Year amortization by $0.4 million;
4. Approval of an amortization period of two-years (versus four-years proposed by NLH) for the **External GRA Hearing Costs RDA**, consistent with the recommendation that the PUB direct that the next NLH comprehensive GRA be filed in 2028. This recommendation will increase 2027 Test Year amortization by $0.4 million; and
5. Approval of financing charges for the **Long-Term Supply Cost Variance Deferral Account** at the short-term borrowing rate (WACC proposed by NLH), considering the nature and expected operation of this RDA, NLH's capacity to finance this RDA through its short-term borrowing facilities and concerns with respect to the inconsistency of higher WACC financing costs and the Government's Rate Mitigation Plan.

2.0 This Evidence Evaluates NLH's Position on the Timing of Its Next GRA and 2027 Test Year Revenue Requirement Proposals and Regulatory Accounting Proposals

This Section of the Evidence provides a summary of NLH's 2026 GRA (2027 Test Year) revenue requirement and regulatory accounting proposals. It also provides an overview of the qualifications and duties to the PUB of Mr. Rainkie and the purpose, scope and organization of the Evidence.

The NLH 2026 GRA is based on a 2027 Test Year and incorporates the Muskrat Falls supply costs within NLH's revenue requirement for the first time since the assets were commissioned. NLH's 2027 Test Year revenue requirement has been mitigated to approximately $798 million through the application of the Government's Rate Mitigation Plan, with NLH's portion of Domestic customer annual rate increases on the Island Interconnected System being limited to the 2.25% targeted in the Rate Mitigation Plan.

The purpose and scope of this Evidence is to evaluate and make recommendations related to NLH's position on the timing of its next GRA and to evaluate and make recommendations on NLH's 2027 Test Year revenue requirement proposals, regulatory accounting proposals and the update of NLH's Intercompany Transactions Costing Guidelines.

2.1 NLH is Requesting Approval of a Targeted 2.25% Rate Increase Effective July 1, 2027 for Domestic Customers on the Island Interconnected System Consistent with the Rate Mitigation Plan

The last comprehensive public review of NLH's revenue requirements and electricity rates by the PUB occurred in 2017 and 2018. That review was based on NLH's 2018 and 2019 Test Years (the last NLH GRA which is referred to as the 2017 GRA) and resulted in PUB Order No. P.U. 16(2019), dated May 7, 2019.

On May 27, 2026, NLH filed the 2026 GRA (2027 Test Year) with the PUB, requesting approval of the following revenue requirement proposals and regulatory accounting proposals[1]:

1. **Rates & Rate Increase:** NLH's proposal is to have its 2027 Test Year revenue requirements, and resulting rates, reflect the costs of providing electricity service and the Government's Rate Mitigation Plan, including approximately $502 million of rate mitigation funding to offset these revenue requirements. NLH's portion of Domestic customer annual rate increases on the Island Interconnected System is limited to the 2.25% targeted in the Rate Mitigation Plan (effective July 1, 2027) and other rate classes on the Island Interconnected System who are supplied by Muskrat Falls (including Island industrial Customers and NLH's Rural Customers) are also subject to the rate mitigation[2];

[1] NLH Letter of Application, Section B, pgs. 7 to 9 and Chapter 5, Section 5.8, pgs. 5.29 and 5.30
[2] Chapter 1, Section 1.1, pg. 1.1

2. **Revenue Requirements**: For the purpose of calculating NLH's 2027 Test Year: (i) a revenue requirement of $798 million (ii) a forecast average rate base of $2.802 billion (iii) a rate of return on rate base/weighted average cost of capital (WACC) of 4.88% in a range of 4.68% to 5.08% (iv) a forecast capital structure for 2027 of approximately 74.5% debt, 21.8% equity and 3.7% zero cost capital[3] (v) a Holyrood conversion rate of 563 kWh per barrel (vi) the continued use of the working capital allowance methodology, including a new and separate working capital allowance related to Muskrat Falls supply costs[4] (vii) proposals with respect to NLH's depreciation rates and methodology based on recommendations in the 2023 Depreciation Study and 2024 Technical Update[5] and (viii) updated Intercompany Transactions Costing Guidelines related to the allocation of shared service departments between NLH's regulated operations and non-regulated operations[6]; and
3. **Regulatory Accounting**: The disposition and amortization of balances in existing regulatory deferral accounts (RDAs), including: (i) Business Systems Transformation Program RDA (ii) Frequency Converter Depreciation RDA (iii) Phase Two Hearing Costs RDA (iv) Reliability & Resource Adequacy Study Review RDA (v) Muskrat Falls PPA Sustaining Capital RDA (vi) Electrification Cost RDA (vii) Return on Equity Rate Change RDA and (viii) External GRA Hearing Costs RDA. The creation of a new Long-Term Supply Cost Variance Deferral Account (LT SCVDA) effective January 1, 2027, with interest calculated based on the WACC in NLH's latest approved test year.

2.2 Mr. Rainkie has 36 Years of Multi-Faceted Experience in Public Utility Leadership, Rate-Regulation and Financial Management & Acknowledges His Duties to the PUB

Mr. Rainkie is an independent regulatory consultant (2017 to present) and works closely with Ms. Derksen in a joint regulation consulting practice to provide a full range of regulatory services to clients that participate in or are impacted by rate-regulation. Areas of focus include regulatory strategy and ratemaking policy, regulatory process matters, revenue requirements and fiscal matters, internal and external cost allocation, rate design, contribution policy, marginal cost-based ratemaking, review of large capital projects, as well as energy transition and integrated resource planning matters.

Mr. Rainkie received a Bachelor of Commerce (Honours) with distinction from the University of Manitoba (1988), majoring in accounting. Mr. Rainkie is a Chartered Accountant (1991) and Chartered Professional Accountant registered with CPA Manitoba and is a Chartered Business Valuator (1993) registered with the Canadian Institute of Chartered Business Valuators.

[3] Chapter 5, Section 5.4.1, Table 5-9, pg. 5.14
[4] Chapter 5, Section 5.3.2, pgs. 5.12 and 5.13
[5] Chapter 5, Section 5.2.5, pg. 5.6
[6] Chapter 3, Section 3.1.2, pgs. 3.8 to 3.9

Mr. Rainkie is responsible for the preparation of evidence related to revenue requirement and regulatory accounting matters before the PUB in this proceeding. Ms. Derksen is responsible for the preparation of evidence related to cost of service and rate design matters before the PUB in this proceeding.

Mr. Rainkie has 36 years of hands on and multi-faceted expertise in public utility leadership, rate-regulation and financial management, with demonstrated experience in applying and integrating this diverse experience into the rate-making framework of complex regulated enterprises. He specializes in providing public utility regulatory and financial advisory services to clients, with an emphasis on the evaluation of regulatory strategy and ratemaking policy and revenue requirement and fiscal matters.

Mr. Rainkie has a deep specialization in all aspects of ratemaking, progressively throughout his career, including acting as an advisor to the Manitoba Public Utilities Board from 1990 to 1994, analyst and managerial roles in the Regulatory Services department of Manitoba Hydro and Centra Gas between 1994 and 2006, senior and executive level responsibilities associated with regulatory affairs between 2006 and 2017 and an independent expert regulatory consultant from 2017 to present.

In addition to his extensive ratemaking experience, Mr. Rainkie's experience relevant to the evidence to be provided in this proceeding includes executive level public utility and financial experience as a former Corporate Treasurer, Corporate Controller, Vice-President of Finance & Regulatory Affairs and Chief Financial Officer and Acting President & Chief Executive Officer of Manitoba Hydro and Centra Gas between 2006 and 2017.

As Chief Financial Officer of Manitoba Hydro and Centra Gas, he was responsible for the executive leadership of the Controller, Treasury and Rates & Regulatory Affairs divisions, the Financial Planning Department and Corporate Risk Management Department. In these roles, Mr. Rainkie had responsibility for overseeing, setting and developing Manitoba Hydro and Centra Gas:

1. Corporate and business unit strategies and financial plans,
2. Financial targets,
3. Long-term financial forecasts,
4. Operating and capital cost budgets,
5. Financing plans and debt management strategies,
6. Regulatory policies and rate applications,
7. Corporate risk management activities; and
8. Financial reporting.

Mr. Rainkie has testified before the Manitoba Public Utilities Board on multiple occasions over the last 25 years, as an independent expert witness on behalf of the Consumers' Association of Canada (Manitoba Branch) (CAC) and the Consumers Coalition and an executive policy and subject matter witness for Manitoba Hydro and Centra Gas.

Mr. Rainkie has provided consulting advice to the Consumers Coalition on a number of Manitoba Public Insurance GRAs before the Manitoba Public Utilities Board with respect to overall case theory, corporate strategy, leading operating cost budgeting practices for regulated utilities and key performance indicators.

Mr. Rainkie has:

1. Provided opinion evidence and testified before the Nova Scotia Energy Board (Nova Scotia Power Inc's Pricing and Terms & Conditions of Service to Municipal Utilities);
2. Provided opinion evidence and testified before the New Brunswick Energy and Utilities Board related to a review for cross-subsidization between Liberty Utilities New Brunswick distribution function and gas sales function; and
3. Provided opinion evidence to the Alberta Utilities Commission related to residential and streetlighting distribution investment policies for four Alberta electric distribution utilities (ATCO, ENMAX, EPCOR and Fortis).

Mr. Rainkie has also provided extensive consulting advice to a residential intervenor (Council of Senior Citizens' Organizations of BC et al or COSCO) over the last six years on numerous regulatory proceedings before the British Columbia Utilities Commission on a range of subject matters, including revenue requirements, major capital project reviews, demand side management reviews, integrated resource plans and rate-setting frameworks - related to natural gas, district energy and electric utilities.

Mr. Rainkie's full curriculum vitae is provided as an attachment to this Evidence.

Duties to the PUB and Independence

Mr. Rainkie acknowledges that he has a duty to provide evidence that is fair, objective and non-partisan, related only to matters within his areas of expertise and to provide such additional assistance as the PUB may reasonably require to determine issues in this proceeding.

2.3 This Evidence Evaluates NLH's Position on the Timing of NLH's Next GRA and 2027 Test Year Revenue Requirement Proposals and Regulatory Accounting Proposals

The purpose of this Evidence is to evaluate NLH's position with respect to the timing of its next GRA and evaluate NLH's revenue requirement and regulatory accounting proposals and provide related observations, conclusions and recommendations to the PUB, for rate-setting purposes.

In this proceeding, Mr. Rainkie is providing this independent evidence on behalf of the Consumer Advocate.

The Sections of the Evidence that follow are organized into the following topic areas:

- **Section 3.0**: Evaluation of NLH's position with respect to the timing of the filing of its next GRA;
- **Section 4.0**: Evaluation of NLH's 2027 Test Year revenue requirement proposals;
- **Section 5.0**: Evaluation of NLH's update of its Intercompany Transactions Costing Guidelines; and
- **Section 6.0**: Evaluation of NLH's 2027 Test Year regulatory deferral account proposals.

Please note the following for the Sections of the Evidence that follow:

- All dollar figures are in $ millions, unless otherwise noted; and
- Many tables have been rounded to the nearest $1 million which may result in immaterial rounding differences from the more detailed figures provided by NLH in its GRA filing and responses to requests for information.

3.0 Robust & Proactive Regulatory Oversight is Critical in an Era of Unprecedented Volatility, Uncertainty, Complexity and Ambiguity and Associated Rate Pressures

This Section of the Evidence evaluates NLH's position that rates for the next three test years (2028 to 2030) should be established through annual rate adjustment applications and that it does not plan to file a comprehensive GRA with the PUB until 2030 (2031 Test Year) at the earliest (minimum of a four year interval until the next GRA).

The reasonableness of NLH's position is considered from a number of perspectives including the unprecedented volatility, uncertainty, complexity and ambiguity (VUCA) in NLH's business, operational and financial environment associated with the energy transition, the expiry of the Rate Mitigation Plan in 2030 and the recent signing of a framework agreement between NLH and Hydro-Quebec related to Churchill Falls.

Additionally, future cost and rate pressures in the next number of years are analyzed including $188 million of revenue requirement offsets for the 2027 Test Year that are not expected to reoccur in this order of magnitude in the future and increasing levels of capital expenditures, escalation of operating costs and build up of regulatory deferral accounts. It is concluded from the analysis that future rate mitigation uncertainty and other cost pressures directionally point to significant revenue requirement and rate pressures to 2030 and beyond.

Collectively, this analysis suggests an approach to PUB regulatory oversight of NLH on a go-forward basis that is more robust, takes a macro-level (top-down) view of the electricity system through proactive policy making, with the primary focus on regulatory effectiveness and protecting the public interest in an environment where the stakes are high for ratepayers and stakeholders. NLH's position is a micro-level (bottom-up) and compliance based approach, with a primary focus on historical test years and administrative efficiency and is risky given the current environment and the potential build up of rate pressures in the next four years.

It is recommended that the PUB direct NLH to (i) file its next comprehensive GRA in 2028 to include both a 2029 Test Year and a 2030 Test Year and (ii) file a medium-term financial forecast of at least 3 additional forecast years (2031, 2032 and 2033) for a total of 5 years of forecasts (2029 to 2033) as part of the comprehensive GRA filing.

The filing of a comprehensive GRA by NLH in 2028 is a balanced approach to ensure the continued effectiveness of the PUB's regulatory oversight while allowing for administrative and regulatory efficiency. These recommendations will give the PUB and intervenors prospective insight into the post 2030 business, financial and rate environment of NLH and allow for proactive understanding of rate pressures and potential rate paths post 2030, in order to consider rate stability and predictability for ratepayers and stakeholders.

These recommendations also allow for timely regulatory consideration of significant capital expenditures while construction is under way, other rate pressures that are forecast to occur and the build-up in regulatory deferral accounts.

3.1 NLH's Approach to Regulatory Oversight by the PUB is Focused Mainly on Historical Test-Years, Compliance-Based Regulation & Administrative Efficiency

NLH's position is that rates effective July 1, 2028, July 1, 2029 and July 1, 2030 be established through annual rate adjustment applications. Under this proposed approach, NLH would apply annually for approval of revised rates rather than filing a new comprehensive GRA based on a new test year for each year. NLH notes that annual updates to rates to reflect recoveries from or balances owed to customers, primarily related to supply costs, are a long-standing practice approved by the PUB for NLH[7]. NLH confirmed that OC2024-062 does not prescribe the rate-setting process that the PUB is to use to approve the targeted rate increases in the Rate Mitigation Plan[8].

NLH's position is that the 2027 Test Year be the only PUB-reviewed test year in effect during the remaining term of the Government's Rate Mitigation Plan through 2030. NLH notes that historically, utilities in Newfoundland and Labrador have used a test-year approach, with comprehensive reviews conducted periodically, often every three to five years, rather than annual test year proceedings. In NLH's view, this approach promotes regulatory efficiency while maintaining regulatory oversight through PUB-approved rate adjustments and deferral account mechanisms. NLH proposes to continue to provide quarterly reporting to the PUB and intervenors on actual financial results, regulatory accounts and rate mitigation funding[9].

The implications from NLH's above-noted positions are that rates for the next three test years (2028, 2029 and 2030) are proposed to be established through annual rate adjustment applications and that it does not plan to file a comprehensive GRA with the PUB until 2030 (2031 Test Year) at the earliest. This proposal would result in at least a four year interval between the 2027 Test Year and a 2031 Test Year.

NLH's proposal for at least a four year interval to the filing of its next comprehensive GRA is concerning as the next GRA becomes mainly an exercise in retrospective accountability and essentially represents a compliance-based approach to regulatory oversight with a primary focus on administrative efficiency.

Under NLH's suggested approach, a GRA process becomes mainly focused on critical assessment of past figures, to check if actual spending matched to approved spending and prudence reviews in terms of looking backward at historical spending and build ups of numerous regulatory deferral accounts and the potential disallowance of imprudent and unapproved costs. This is especially the case if NLH only provides one test-year of cost and revenue forecasts, as is the situation in the current GRA, with only the 2027 Test Year and eight historic years (2019 actuals to 2026 forecasts) under review. NLH had considered filing both 2026 and 2027 test years as part of the 2026 GRA but as a result of delays and other regulatory priorities, the filing of a 2026 Test Year

[7] CA-NLH-224 a
[8] CA-NLH-352
[9] CA-NLH-224 c d

was no longer practical. NLH also considered filing a 2028 Test Year but a 2028 forecast had not been developed as part of the GRA preparation process and doing so would have further delayed the filing of the GRA[10].

Further, under NLH's suggested approach, the focus tends to be more of a compliance focus of whether the calculations of revenue requirements and rates in accordance with the regulatory rules (regulatory methodology/framework, past PUB Orders and Government OICs).

Lastly, NLH's focus in delaying the next comprehensive GRA for at least four years is in large part based on administrative and regulatory efficiency.

In the sub-sections that follow, the reasonableness of NLH's proposal for a minimum four year interval before filing of the next comprehensive GRA is reviewed considering the current and expected environment in the energy sector and associated affordability and rate pressure concerns on a go-forward basis.

3.2 The Energy Transition is Inherently an Era of Unprecedented Volatility, Uncertainty, Complexity and Ambiguity for Electric Utilities such as NLH

Utilities across Canada and North America are grappling with the threats and opportunities that are associated with the disruptive/transformative forces of the energy transition that are reshaping the energy sector.

Regulated monopoly electric utilities have historically operated in a stable environment with a long-standing traditional cost of service business model. Under this legacy business model, the utilities built centralized power plants and had stable revenue streams based on selling electricity in one direction to passive consumers (growth in consumption) and receiving financial returns based on capital expenditures (growth in rate base).

The transformative forces of the energy sector are disrupting the many decades old legacy cost of service business model of electric utilities. At a high level, there are uncertainties associated with government energy and climate policy, customer behaviour and expectations and emerging energy resources and technologies. Customer expectations are changing, and concepts being discussed in the energy sector range from passive consumers (consume energy only), to prosumers (consumer and producer of energy) to flexumer (actively managing when energy is consumed and providing produced energy back to the grid at the peak times of need).

In this environment, utility business model elements will need to be reconsidered in terms of what is reliable service and providing value to customers, what is the new cost structure in this environment and what revenue streams are required to match the cost structure and remain financially viable. Utility operating model elements such as organizational structure, processes,

[10] PUB-NLH-009

people, projects and systems will also need to be revised in order to execute adaptations to the traditional business model.

The energy sector is considering alternative business models/concepts such as energy as a service, energy as a platform, virtual power plants and distributed energy resources to respond to customer expectations and develop new sources of revenue.

A helpful framework to use to summarize the transformative forces/structural changes of the energy transition is the 5 D's framework – **decarbonization** (replacing fossil fuels with renewable energy sources), **decentralization** (shifting from massive, centralized power plants to localized energy generation), **democratization** (everyday consumers/communities having a direct role in producing, managing and benefiting from energy), **deregulation** (expanding energy services, adapting business models and market competition) and **digitization** (using smart technologies to optimize power grids in real time).

These transformative forces/structural changes have created an unprecedented era of **volatility, uncertainty, complexity and ambiguity** (VUCA) for electric utilities such as NLH. While by no means an exhaustive list, the VUCA for electric utilities includes unpredictable power flows from intermittent resources, revenue instability, shifts in policy/regulatory frameworks, stranded asset risks, managing multi-directional smart grids, cyber security risks, integrating massive amounts of data with legacy systems, threats of death spirals and electrification boom and blurred industry boundaries with third party energy providers.

While NLH's 2026 GRA filing is mainly focused on historical/retrospective information on costs and revenues and regulatory deferral accounts and a single 2027 Test Year forecast, there are portions of the application and associated hearing materials that acknowledge the forward-looking threats and opportunities associated with the 5 D's and associated VUCA:

- **NLH 2026 GRA Filing**: NLH acknowledges that the energy sector is evolving, including technological innovation, increased demand/consumption through broad electrification. NLH has a role in informing and enabling public policy developments associated with electrification and increased wind energy integration and is focused on displacing fossil fuel consumption. NLH notes that electrification and market pressures have driven increased costs for both capital investments and operating costs, which have introduced operational risk[11];
- **NLH 2025 Annual Report**: NLH is prioritizing supporting the growth of renewable energy by collaborating with Government and industry stakeholders to evaluate and advance viable projects, advancing electrification and demand management, optimizing the value of provincial energy resources and integrating renewable energy resources in local and isolated communities[12];

[11] Chapter 1, Section 1.4, pgs. 1.13 and 1.14
[12] CA-NLH-084 a – 2025 Annual Report (link) pg. 37

- **NLH 2025 MD&A**: NLH outlines key business risks to include strategy risks associated with the evolution of the energy industry and system expansion as changes in provincial economic forecasts, federal and provincial energy policy, customer usage patterns and industrial development can be expected to impact how energy is utilized in the province and beyond[13]; and
- **NLH 2026-2030 Strategic Plan**: NLH acknowledges navigating the energy transition and that demand for electricity is outpacing traditional utility timelines for approval and construction of the new developments that are necessary to meet this demand. NLH also outlines external factors that present challenges and enable solutions such as climate change and challenging weather events, cybersecurity threats, geopolitical uncertainty, global supply chain disruptions, tightening labour markets and system complexity and growth[14].

Overall, it is noted that there is a paucity of strategically oriented and top-down materials in the NLH 2026 GRA filing to facilitate robust and prospective regulatory oversight by the PUB and understanding by intervenors, in the era of the energy transition and associated VUCA. While rate-regulation necessarily focuses on figures to set rates, those figures do not exist in a vacuum. Rather, the figures provided in the revenue requirement forecasts are a direct product of the strategic direction, aspirations, strategies and risk tolerances of the regulated utility which are then translated into plans from which the figures (costs and revenues) are derived.

There are a number of observations where enhancements could be made to the strategically oriented and top-down materials provided by NLH in its GRA filings, which are summarized as follows:

1. **Strategic Plan or Overarching Business Strategy[15]**: NLH did not file its strategic plan as part of its GRA filing – it had to be requested in the first round of requests for information. NLH's 2026 to 2030 strategic plan and response to information request addressing the external transformative forces[16] is typical of the outcome of strategic planning exercises in terms of long lists of laudable initiatives that are mainly inward facing and represent operational imperatives rather than strategic imperatives (involving choices and trade-offs). NLH's strategic plan appears to be mainly focused on monitoring, readiness and engagement activities (qualitative focus) to largely optimize its legacy business and operating model - rather than building a strategy around the strategic themes and does not include quantitative performance metrics and associated targets. It does not yet represent an overarching business strategy that is focused on adapting its business model

[13] CA-NLH-028 b – 2025 Annual Report (link) pg. 16
[14] CA-NLH-028 a – 2026-2030 Strategic Plan (link) pg. 5
[15] CA-NLH-028 a c and CA-NLH-48 a b and CA-NLH-245
[16] CA-NLH-236

and operating model to navigate the energy transition and associated external facing transformative forces;

2. **Risk Management Report & Risk Tolerances**[17]: NLH did not file a risk management report with its GRA filing and when requested to do so the utility provided a link to its management discussion and analysis (summary of key business risks) as part of its 2025 Annual Report. When requested to provide information with respect to risk quantification, risk tolerances, residual risk assessment and risk treatment associated with its key business risks, NLH refused to provide this information and provided a generic response that such information is not relevant to the 2027 Test Year;
3. **Asset Management Maturity & Strategic Asset Management Plan (SAMP)**[18]: NLH indicated that it did not have a formally documented SAMP and that an external assessment of its asset management needs and readiness assessment was conducted in 2022 with a number of opportunities (39 recommendations) for improvement and that individual maturity assessments generally ranged from 12% to 33%. NLH also indicated that the PUB had engaged a consultant in 2025 to perform a gap assessment against Asset Management Standards but could not comment on this review as it had not yet been released by the PUB;
4. **Debt Management Strategy**[19]: When requested to provide its policy and guidelines with respect to limits on the use of variable rate debt in its debt portfolio, NLH responded that it does not have a prescribed target and percentage allocation or standalone limit for variable-rate debt and that short-term variable rate debt and long-term variable-rate debt represents 0% of its total debt portfolio as it is focused on limiting its exposure to variable interest rate fluctuations. NLH also indicated that it is not aware of the PUB review of its debt management strategies at a prior GRA proceeding; and
5. **Artificial Intelligence (AI) Strategy**[20]: NLH discussed the leveraging of technology within the organization supports all aspects of its business, mitigates operational risk and enables workforce productivity – but indicated that it is at the early stages of implementing an enterprise approach to AI.

It is recommended that the PUB direct NLH to provide the above-noted strategically oriented documents as part of its future GRAs – to aid in strengthening regulatory oversight and provide critical context to the PUB and intervenors in terms of how strategic direction, aspirations, strategies and risk tolerances shape utility plans and revenues and cost estimates that are included in proposed revenue requirements in GRA filings.

It is also noted that the rate base/rate of return (RBROE) rate setting framework is a strict and formulaic rate-setting methodology that is of questionable relevance to a crown-owned monopoly such as NLH, given that RBROE rewards utilities for spending on capital expenditures.

[17] CA-NLH-028 b and CA-NLH-235
[18] CA-NLH-18 b and CA-NLH-231
[19] CA-NLH-100 c d, CA-NLH-274 and CA-NLH-275
[20] CA-NLH-029 and CA-NLH-237

The formulaic nature of RBROE makes it difficult to rate-smooth without the extensive use of regulatory deferral accounts. As the energy transition progresses and the legacy business model is adapted, adjustments to the rate-setting framework are likely necessary to provide the appropriate incentives to utilities.

While not directly related to the energy transition, the recent signing of a framework agreement (Definitive Cooperation and Implementation Agreement or "DCIA") between NLH and Hydro-Quebec related to Churchill Falls on August 17, 2026, merits mention in the context of the VUCA associated with NLH. It is understood that the agreement is non-binding and that the final long-form contracts are still in the process of being negotiated. Given the recency and non-binding nature of the DCIA, the potential operational, financial and rate impacts on NLH have not been tested on the record of this proceeding.

3.3 There are Significant Concerns with respect to the Uncertainty and Sustainability of a Rate Mitigation Plan in 2031 and Beyond

The Rate Mitigation Plan has a profound impact on NLH's 2027 Test Year revenue requirements. The following table provides an overview of how the components of NLH's revenue requirement have changed between the 2019 Test Year (last GRA) and 2027 Test Year and how the Muskrat Falls supply costs and government directed rate mitigation funding impact the proposed revenue requirements for the 2027 Test Year[21].

Table 1

Revenue Requirement Comparison - 2027 Test Year vs 2019 Test Year ($ Millions)				
	1	**2**	**3**	**4**
			(1-2)	**(3/2)**
			$	**%**
	2027	**2019**	**Increase**	**Increase**
Revenue Requirement Component	**Test Year**	**Test Year**	**(Decrease)**	**(Decrease)**
Operating Costs	156	137	19	14%
Fuels	106	220	(114)	-52%
Power Purchases	67	81	(14)	-17%
Depreciation & Accretion	118	86	32	37%
Other Adjustments	(64)	(7)	(57)	814%
Return on Rate Base	137	126	11	9%
Revenue Requirement Reviewable by PUB (A)	**520**	**643**	**(123)**	**-19%**
Muskrat Falls Supply Costs (B)	780	-	780	
Revenue Requirement before Rate Mitigation (C=A+B)	**1,300**	**643**	**657**	**102%**
Rate Mitigation Funding (D)	(502)	-	(502)	
Net Revenue Requirement (E=C-D)	**798**	**643**	**155**	**24%**

[21] Chapter 5, Section 5.2, Table 5-1, pg. 5.2

The key observations with respect to Table 1, are as follows:

1. The 2027 Test Year revenue requirements that are subject to PUB review and regulatory adjustment (referred to as "reviewable by the PUB" in this Evidence) are comprised of operating costs, fuel costs, power purchases, depreciation & accretion, other adjustments and return on rate base;
2. The 2027 Test Year **revenue requirements** that are **reviewable by the PUB** total $520 million which represents a decrease of $123 million or 19% in comparison to the 2019 Test Year amount of $643 million;
3. OC2013-343 and the Muskrat Falls Project Exemption Order expressly provide that all Muskrat Falls Supply Costs are fully recoverable through Island Interconnected System customer rates and are not subject to disallowance, reduction or regulatory adjustment by the PUB (referred to as "not reviewable by the PUB" in this Evidence)[22];
4. The 2027 Test Year **Muskrat Falls Supply Costs** that are not reviewable by the PUB total $780 million;
5. The 2027 revenue requirements **before rate mitigation funding** total $1.3 billion and represent a $657 million or 102% increase as compared to the 2019 Test Year approved revenue requirements of $643 million that flow from the last NLH GRA;
6. Total 2027 Test Year revenue requirements that are reviewable by the PUB of $520 million, represent 40% of the $1.3 billion of revenue requirements before rate mitigation funding;
7. **Rate mitigation funding** for the 2027 Test Year of $502 million has been back calculated[23] by NLH to derive the 2.25% capped increase in rates in accordance with the Rate Mitigation Plan. This $502 million Rate Mitigation Funding reduced the 2027 Test Year revenue requirements by 39% ($502 million/$1.3 billion);
8. The total proposed net 2027 Test Year revenue requirements **including rate mitigation funding** are $798 million – which represents an increase of $155 million or 24% as compared to the 2019 Test Year approved revenue requirements of $643 million; and
9. The **net increase** in the 2027 Test Year revenue requirements of $155 million is comprised of (i) a net increase related to Muskrat Falls of $278 million ($780 million of Muskrat Falls Supply Costs less $502 million of rate mitigation funding), offset by (ii) a $123 million decrease in costs that are reviewable by the PUB.

In summary, NLH's 2027 Test Year revenue requirement would have more than doubled (102% increase) in absence of the rate mitigation funding.

The fact that the Muskrat Falls Supply Costs that represent 60% of NLH's revenue requirements before rate mitigation funding ($780 million/$1.3 billion) and that these costs are not reviewable

[22] Chapter 4, Section 4.1, pg. 4.1
[23] CA-NLH-059 a

by the PUB is concerning and problematic. This situation represents a departure from standard utility regulation/practice that normally includes prudence reviews of completed capital projects with the burden of proof on the utility, places the utility at financial risk of disallowance of imprudent expenditures, disrupts the standard regulatory compact (utility receives a monopoly in exchange for independent regulatory oversight) and interferes with the quasi-judicial autonomy of the independent regulatory body.

There is significant uncertainty with respect to rate mitigation funding after the Rate Mitigation Plan ends in 2030 and concerns with respect to the sustainability of the rate mitigation funding. The current Rate Mitigation Plan is a temporary solution with a finite expiration date and represents a cross-subsidy from NLH's non-regulated operations to its regulated operations. In contrast, the Muskrat Falls Supply Costs are permanent costs and a long-term structural solution to preserve rate stability for ratepayers is required.

There is no certainty with respect to a post-2030 Rate Mitigation Plan, the quantum of that plan and how that plan might be structured. NLH was requested to provide a status update on the development of a rate mitigation plan for the post-2030 period and to provide projections of the amount of rate mitigation funding that would be required in the post-2030 period (2031 to 2035 forecast)[24]. In response to these requests for information, NLH provided a generic response that in its opinion, this information was not necessary for an understanding of the matters to be considered in the 2026 GRA.

The sources of the rate mitigation funding for 2027 to 2030 are not sufficiently transparent and there is no information with respect to the risks and sustainability of the rate mitigation funding sources in 2030 and beyond.

NLH was requested to provide a description and breakdown of the various internally generated funding sources for rate mitigation from 2024 to 2030 [25]. In response, NLH did not provide the requested breakdown, instead indicated that the projection of the internally generated sources of rate mitigation funding is calculated based on the funding required after the Government of Canada convertible debenture funding and Lower Churchill Project dividends are considered. NLH also indicated that these funds are managed on a pooled basis and as a result it does not attribute specific portions of internally generated funding to individual cash sources. NLH provided a high-level response that internally generated rate mitigation funds include dividends from oil and gas profit and electricity export profit[26].

NLH was requested to identify all sources of rate mitigation funding, including internal sources for the 2027 Test Year, explain the risks associated with each source and to also explain how it satisfies itself that the funding of upwards of $350 million per year of rate mitigation from

[24] CA-NLH-057 a b
[25] CA-NLH-059 d and CA-NLH-060 d
[26] CA-NLH-247

internal sources is financially sustainable through 2030[27]. In response, NLH indicated that internal sources of funding is dependent on the financial performance and cash generation of the entities that provide those funds. NLH noted that based on current forecasts, NLH expects identified funding sources that are able to support the 2027 Test Year requirements and that should a material variance be identified it would assess options and engage with the Government as appropriate. NLH did not respond to the portion of the request for information that requested how it satisfies itself that upwards of $350 million of rate mitigation funding from internal sources is financially sustainable through 2030.

In summary, inadequate information with respect to the sources, risks and sustainability of rate mitigation funding through to 2030 or in 2031 and beyond were obtained through two rounds of requests for information of NLH.

The inadequate information on future sources and risks of rate mitigation funding is concerning given the significant impacts on NLH's future revenue requirements in the absence of such funding – as is demonstrated by a doubling of revenue requirements between the 2019 Test Year and 2027 Test Year before such funding – and the fact that this funding reduced 2027 Test Year revenue requirements by 39%.

The inadequate information on future sources and risks of rate mitigation funding would tend to support a more robust and proactive/prospective approach to regulatory oversight over the next three test years in order to protect the public interest and rate stability for ratepayers, than that which is proposed by NLH.

3.4 There are $188 Million of Additional Revenue Requirement Offsets in the 2027 Test Year Primarily Related to In-Service of Muskrat Falls Assets that are Not Expected to Reoccur in Future Test Years

There are additional revenue requirement offsets in the 2027 Test Year that are primarily related to the in-service of the Muskrat Falls Assets. The table below re-arranges the components of the 2027 Test Year revenue requirements from Table 1 of this Evidence, to highlight these additional offsets.

[27] CA-NLH-058 c and CA-NLH-063

Table 2

Revenue Requirement Analysis - 2027 Test Year vs 2019 Test Year ($ Millions)				
	1	2	3	4
			(1-2)	(3/2)
			$	%
	2027	2019	Increase	Increase
Revenue Requirement Component	**Test Year**	**Test Year**	**(Decrease)**	**(Decrease)**
Operating Costs	156	137	19	14%
Depreciation & Accretion	118	86	32	37%
Return on Rate Base	137	126	11	9%
Sub-total (A)	**411**	**349**	**62**	**18%**
Fuels	106	220	(114)	-52%
Power Purchases	67	81	(14)	-17%
Other Adjustments	(64)	(7)	(57)	814%
Sub-total (B)	**109**	**294**	**(185)**	**-63%**
Revenue Requirement Reviewable by PUB (C=A+B)	**520**	**643**	**(123)**	**-19%**
Muskrat Falls Supply Costs	780	-	780	
Rate Mitigation Funding	(502)	-	(502)	
Muskrat Falls Costs Net of Rate Mitigation Funding (D)	**278**	**-**	**278**	
Net Revenue Requirement (E=C+D)	**798**	**643**	**155**	**24%**

The key observations with respect to Table 2, are as follows:

1. The **total increase** in NLH's 2027 Test Year revenue requirements related to operating costs, depreciation & accretion and return on rate base represent $62 million or an 18% increase as compared to the approved 2019 Test Year;
2. The **total decrease** in NLH's 2027 Test Year revenue requirements related to fuel costs, power purchases and other adjustments represent a $185 million or a 63% decrease as compared to the approved 2019 Test Year;
3. There is (i) a $130 million decrease in fuel costs, (ii) a $40 million increase in net export revenues (in other adjustments) and (iii) an $18 million increase in transmission tariff revenues (in other adjustments) – that are primarily related to the commissioning of the **Muskrat Falls Assets**. These amounts total an approximate $188 million decrease (offset) to the increase in 2027 Test Year revenue requirements[28]; and

[28] CA-NLH-240

4. The 2027 Test Year revenue requirements **reviewable by the PUB** have decreased by $123 million or 19% relative to the approved 2019 Test Year, primarily as a result of (i) the $62 million increase in operating costs, depreciation & accretion and return on rate base that (ii) is more than offset by the $185 million decrease in fuel costs and other adjustments (increases in net export revenues and transmission revenues) as a result of the commissioning of the Muskrat Falls Assets.

The key point with respect to this analysis, is that the $188 million offset to the 2027 Test Year revenue requirements that is primarily attributed to the commissioning of the Muskrat Falls Assets is not expected to reoccur in this order of magnitude in NLH's subsequent future test years.

3.5 There are Other Future Cost and Rate Pressures Associated with Increased Levels of Capital Expenditures, Escalation of Operating Costs and Build Up of Regulatory Deferral Accounts

As noted in a number of places in NLH's 2026 GRA filing, there are also other cost pressures associated with replacing aging infrastructure, investing in new generation to meet future demand, and inflationary and supply chain pressures.

High level information with respect to NLH's actual and forecast **capital expenditures** related to sustainment of assets and growth-related investments, can be summarized as follows[29]:

1. From **2020 actual to 2027 forecast**, NLH indicates that total capital expenditures are projected to be $1.675 billion over this 8-year period or an average of $209 million per year – with non-major capital expenditures averaging $132 million per year and major capital expenditures averaging $77 million per year over that period;
2. From **2028 forecast to 2030 forecast**, NLH indicates that total capital expenditures are forecast to be $1.957 billion over this 3-year period or an average of $652 million per year – with non-major capital expenditures averaging $171 million per year and major capital expenditures averaging $481 million per year over that period; and
3. **Average capital expenditure per year** is expected to be over 3 times higher from 2028 to 2030 as compared to 2020 to 2027 ($652 million/$210 million = 3.1 times).

In terms of cost pressures related to regulated **operating costs**, the following highlights are noted[30]:

[29] CA-NLH-081 a b
[30] Chapter 2, Section 2.2.4, pgs. 2.22 to 2.27

1. NLH has not provided **economic increases** to non-union employees for the 7-year period from 2016 to 2022;
2. Approximately 60% of NLH's operating costs relate to **labour costs**[31];
3. Southlea completed a **third party review** of NLH's non-union and executive **compensation** and concluded that NLH was 12% below the market 50th percentile of a utility comparator group on a total remuneration basis for the non-union/non-executive workforce and approximately 50% below the market 50th percentile for executive compensation on a total remuneration basis (based on 2023 data);
4. To address these survey findings and start to realign its position with its comparator market, NLH **increased compensation levels**, including economic increases of 4% in 2024 and 4% in 2025 – but NLH continued to be approximately 11% below its 50th percentile target at the end of 2025. NLH has also forecast salary adjustments through the 2027 Test Year to close the gap with comparators;
5. To support work required now and into the future, NLH's **FTE complement** has increased by approximately 5.6% (from 835 to 882) in the 8 years between the 2019 Test Year and 2027 Test Year;
6. **Non-labour costs** have also demonstrated significant inflationary impacts since the last GRA, including professional services, materials, contract labour and other maintenance related costs[32]; and
7. While NLH asserts that it has successfully mitigated inflationary pressures since the 2019 Test Year, in its view, it is **not feasible** or **sustainable** to continuously absorb these pressures and grow at the same time without impacting safe and reliable delivery service[33].

NLH has provided information that the balances in **regulatory deferral accounts** included in rate base are forecast to increase from approximately $119 million at the end of the 2027 Test Year to $173 million at the end of 2030, a growth of $54 million or 45% over that 3-year period (excluding the impact of the proposed AFUDC Deferral Account that was denied by the PUB in Order No. P.U. 30(2026))[34]. The balance in these regulatory deferral accounts at the end of 2019 were approximately $90 million[35].

There is significant uncertainty associated with the balances and dispositions of the Holyrood TGS Accelerated Depreciation Deferral Account and Long-Term Supply Cost Variance Deferral Account, which are discussed in Section 6.7 and Section 6.8 of this Evidence, respectively.

[31] Chapter 2, Section 2.3.1, pg. 2.30
[32] Chapter 2, Section 2.3.2, pg. 2.31
[33] Chapter 3, Section 3.1.1, pg. 3.3
[34] CA-NLH-192, Attachment 1, pg. 1
[35] CA-NLH-193, Attachment 1, pg. 1

It is also noted that the International Accounting Standards Board (IASB) recently (May of 2026) issued a permanent standard for regulatory accounting (IFRS 20 – Regulated Assets and Regulated Liabilities) which NLH expects to adopt effective January 1, 2029. The implications of this new permanent regulatory accounting standard on NLH's regulatory deferral account balances and forecast have not yet been assessed by NLH[36].

3.6 Rate Mitigation Uncertainty and Other Cost Pressures Directionally Point to Significant Revenue Requirement and Rate Pressures to 2030 and Beyond

There are uncertainties related to the energy transition and future rate mitigation funding as well as other cost pressures associated with replacing aging infrastructure, investing in new generation to meet future demand, inflationary and supply chain pressures and the potential for build up of costs in regulatory deferral accounts. Together these uncertainties and other cost pressures directionally point to significant revenue requirement and rate pressures to 2030 and beyond for NLH.

The uncertainties related to the energy transition, uncertainties related to future rate mitigation funding and non-recurring additional offsets primarily as a result of the commissioning of Muskrat Falls Assets have been outlined in Sections 3.2, 3.3 and 3.4 of this Evidence. Additional cost and rate pressures have been discussed in Section 3.5 of this Evidence.

The information on the record of this proceeding makes it difficult to quantify the rate mitigation revenue uncertainty and the revenue requirement and rate pressures that would build up as a result of the NLH proposal to file its next comprehensive GRA in 2030 (2031 Test Year) at the earliest. NLH was requested to provide the revenue requirement analysis and financial results and forecasts (schedules D-I and D-II, pages 1 to 7) to include 2028 forecasts to 2030 Forecasts, but NLH indicated that this information was not available as its long-term forecast had not yet been fully updated to reflect all assumptions, methodologies and proposals contained within NLH's 2026 GRA[37].

If available in a comprehensive forecast, this financial forecast information would have allowed the use of the 2030 forecasts as a rough proxy for the rate mitigation revenue uncertainty and revenue requirement pressures associated with a 2031 Test Year (given that 2030 is only one year in advance of 2031).

In the absence of a comprehensive 2030 forecast, such an analysis of prospective rate pressures had to be pieced together in the following table from various sources of information in the requests for information as well as some simplifying assumptions (stress illustration). Please note that the analysis in Table 3 below normalizes out the impact of the assumption of decommissioning of the Holyrood TGS in March of 2030 - from operating costs, fuel costs and

[36] CA-NLH-193 c and CA-NLH-324
[37] CA-NLH-084 b and CA-NLH-267

depreciation & accretion - given the uncertainty associated with the timing of this decommissioning. The normalization adjustments related to the Holyrood TGS are outlined in the sources and assumptions provided below Table 3.

Table 3

Revenue Requirement Analysis (No Rate Mitigation Funding) - 2030 Forecast vs 2027 Test Year ($ Millions)				
	1	2	3	4
			(1-2)	(3/2)
			$	%
	2030	2027	Increase	Increase
Revenue Requirement Component	**Forecast**	**Test Year**	**(Decrease)**	**(Decrease)**
Operating Costs	173	156	17	11%
Fuels	120	106	14	13%
Power Purchases	63	67	(4)	-6%
Depreciation & Accretion	150	118	32	27%
Other Adjustments	(56)	(64)	8	-13%
Return on Rate Base	172	137	35	26%
Revenue Requirement Reviewable by PUB (A)	**622**	**520**	**102**	**20%**
Muskrat Falls Supply Costs (B)	823	780	43	6%
Revenue Requirement Before Rate Mitigation (C=A+B)	**1,445**	**1,300**	**145**	**11%**
Rate Mitigation Funding (D)	-	(502)	502	
Net Revenue Requirement (E=C-D)	**1,445**	**798**	**647**	**81%**

The sources and assumptions with respect to Table 3, are as follows:

1. Forecast **operating costs** of $152 million for 2030[38] are increased by $21 million to normalize the Holyrood operating costs of $7 million[39] for the first quarter of 2030 to $28 million ($7 million * 4) for a full year;
2. Forecast **fuel costs** of $94 million for 2030[40] are increased by $26 million ($70 million - $44 million) to normalize the Holyrood fuel costs of $44 million up to the 2029 fuel cost forecast of $70 million[41];
3. Forecast **power purchase costs** for 2030 are $63 million per NLH[42];

[38] CA-NLH-261
[39] NLH 2027 Capital Budget Application, CA-NLH-045 a, Table 1
[40] CA-NLH-087 b
[41] NLH 2027 Capital Budget Application, CA-NLH-045 a, Table 1
[42] CA-NLH-088 b

4. Forecast **depreciation & accretion** of $128 million for 2030[43] are increased by $22 million ($29 million - $7 million) to normalize the Holyrood depreciation of $7 million up to the 2029 depreciation forecast of $29 million[44];
5. Forecast **other adjustments** for 2030 are $56 million per NLH[45];
6. Forecast **return on rate base** for 2030 has been estimated using NLH's forecast average 2030 rate base of $3.519 billion[46] at an overall WACC of 4.88%[47] (held constant to the 2027 Test Year WACC) for an estimate of $172 million;
7. Forecast **Muskrat Falls Supply Costs** for 2030 are based on NLH's estimates of $372 million related to the PPA[48], and $456 million related to the TFA[49], less $5 million deferred into the Muskrat Falls Sustaining Capital RDA[50]; and
8. It is **assumed** in this analysis (which is a proxy for 2031 Test Year revenue requirements) that there is **no rate mitigation funding** considering the uncertainty and concerns with respect to sustainability of this funding as outlined in Section 3.3 of this Evidence.

The key observations with respect to Table 3, are as follows:

1. Based on the assumptions noted above, **total costs** (including Muskrat Falls Supply Costs) **before rate mitigation** would increase by $145 million. This $145 million increase when compared to the 2027 Test Year revenue requirements of $798 million, would represent an 18% increase in revenue requirements ($145 million/$798 million);
2. Assuming **no rate mitigation funding**, would result in a $502 million increase in revenue requirements, which would represent a 63% increase in revenue requirements ($502 million/$798 million);
3. The **combined impact** of cost increases and the assumption of no rate mitigation funding would result in a $647 million increase in revenue requirements, which would represent an 81% increase in revenue requirements ($647 million/$798 million);
4. There are likely even **greater cost pressures** than are estimated in Table 3. There is a lag of the significant capital expenditures that are nearly $2.0 billion from 2028 to 2030 entering service, being included in rate base and impacting depreciation and return on rate base. NLH has not provided any information with respect to the additional rate pressures in 2031 and beyond once these capital expenditures are fully in-service and fully impact depreciation and return on rate base;

[43] CA-NLH-090 d
[44] CA-NLH-268
[45] CA-NLH-082 b
[46] PUB-NLH-008
[47] Chapter 5, Section 5.4.1, Table 5-9, pg. 5.14
[48] CA-NLH-032 b
[49] CA-NLH-045 b
[50] CA-NLH-032 b

5. NLH has used a simple **cost escalation factor** of around 2.3% to 2.5%[51] to estimate operating costs between 2028 and 2030, rather than detailed forecasts of the components of operating costs. Given the cost pressures described in NLH's GRA filing and potential economic increases to move towards its targeted compensation comparator, there is significant risk that these estimates could be higher once detailed operating forecasts are prepared for a future GRA; and
6. Table 3 does not estimate the impact of build up of **regulatory deferral accounts** between now and the next GRA and the associated impact on rates.

In summary, there are significant risks to rate stability for ratepayers as a result of the uncertainty associated with post-2030 rate mitigation funding and cost pressures that are expected to build up in the interval before the next GRA - that NLH is proposing would be based on a 2031 Test Year, at the earliest.

3.7 Robust & Proactive Regulatory Oversight by the PUB is Critical in an Era of Unprecedented Volatility, Uncertainty, Complexity and Ambiguity and Associated Rate Pressures for NLH

In summary, Sections 3.2 to 3.6 of this Evidence outline the following observations:

1. The **energy transition** is inherently an era of unprecedented VUCA for electric utilities such as NLH;
2. The recent signing of the **DCIA** between NLH and Hydro-Quebec related to Churchill Falls adds to this VUCA;
3. There are significant concerns with respect to the uncertainty and sustainability of a Rate Mitigation Plan and associated **rate mitigation funding** in 2031 and beyond;
4. There are $188 million of **additional revenue requirement offsets** in the 2027 Test Year primarily associated with the in-service of the Muskrat Falls Assets that are not expected to reoccur in future test years;
5. There are other **future cost** and **rate pressures** associated with increased levels of capital expenditures, escalation of operating costs and build up of regulatory deferral accounts; and
6. Future rate mitigation uncertainty and other cost pressures directionally point to **significant revenue requirement** and **rate pressures** to 2030 and beyond.

Collectively and directionally, the above noted observations (and supporting analysis) with respect to VUCA and future rate pressures in NLH's business and financial environment would suggest an approach to regulatory oversight on a go-forward basis that is more robust and

[51] CA-NLH-261

proactive/prospective. The purpose of regulatory oversight is to take a macro-level (top-down) view of the electricity system through proactive policy making, with the primary focus on regulatory effectiveness and protecting the public interest in an environment where the stakes are high for ratepayers and stakeholders. This approach is consistent with the PUB's general supervisory power over utilities and a future-test year regulatory construct/framework that focuses forward on strategies, plans and associated revenue requirements and not backward on historical revenues and expenses.

This suggested approach is in contrast to NLH's more micro-level (bottom-up) and compliance based approach of tracking and reporting historical financial information against regulatory rules with a primary focus on administrative efficiency (as described in Section 3.1 of this Evidence).

3.8 It is Recommended that the PUB Direct NLH to File its Next Comprehensive GRA in 2028 and that this GRA Include Both a 2029 Test Year and 2030 Test Year and Forecasts to 2033

It is recommended that the PUB direct NLH to file its next comprehensive GRA in 2028 and that this GRA include both a 2029 Test Year and a 2030 Test Year. It is also recommended that the PUB direct NLH to file a medium-term financial forecast of at least 3 additional forecast years (2031, 2032 and 2033) for a total of 5 years of forecasts (2029 to 2033) as part of the next comprehensive GRA filing.

NLH's position of a minimum four year interval (2031 +) until the filing of its next GRA is risky from the perspective of the VUCA that is inherent in NLH's business and financial environment and building up of four years of rate pressures. Four or more years without the accountability and transparency associated with a comprehensive GRA is too long in this environment.

NLH's proposal to maintain quarterly reporting to the PUB and intervenors between GRA filings is appreciated but is no substitute for the accountability and transparency associated with the filing of a comprehensive GRA and the associated public review process. A comprehensive GRA is the only regulatory proceeding that integrates the top-down view of NLH's rate pressures and revenue requirements. Fragmented reporting of components of rates does not substitute for a comprehensive GRA.

The filing of a comprehensive GRA by NLH in 2028 is a balanced approach to ensure the continued effectiveness of the PUB's regulatory oversight while allowing for administrative and regulatory efficiency.

The filing of a comprehensive GRA with 2029 and 2030 Test Years coincides with the midpoint of the Rate Mitigation Plan and the filing of at least three additional years of forecasts to 2033 in the GRA will give the PUB and intervenors prospective insight into the post 2030 business, financial and rate environment of NLH. These prospective insights include progress towards the energy transition, trends in load changes/electrification, the expiry of the current Rate Mitigation Plan and negotiations with respect to Churchill Falls. This approach will allow for proactive

understanding of rate pressures and potential rate paths post 2030, in order to consider rate stability and predictability for ratepayers and stakeholders.

These recommendations also allow for timely regulatory consideration of (i) the planned $2 billion of capital expenditures while construction is under way (ii) other rate pressures that are forecast to occur and (iii) the build-up of balances in regulatory deferral accounts.

The recommendation of a two year interval until the filing of the next comprehensive GRA by NLH is consistent with the interval that was directed by the PUB in the decision flowing from the 2017 GRA (2018 and 2019 Test Years) where the PUB directed NLH to file its next GRA in 2020, for rates based on a 2021 Test Year[52]. The recommendations of a two year interval until the filing of the next comprehensive GRA by NLH and the inclusion of at least two forward test years is consistent with GRA cadence of other crown-owned Hydro utilities such as BC Hydro, Manitoba Hydro and Hydro-Quebec, which file regular GRAs in intervals of two (2) to three (3) test years.

[52] Order No. P.U. 16(2019), pg. 61

4.0 There are Recommended Adjustments & Outstanding Concerns Related to NLH's 2027 Test Year Revenue Requirement Proposals

This Section of the Evidence evaluates NLH's 2027 Test Year revenue requirement proposals, focusing on issues related to operating costs, depreciation & accretion and return on rate base (regulated interest costs and regulated net income).

NLH's assertion that its 2027 Test Year operating costs are forecast to be approximately 10% lower than the 2019 Test Year forecast in real dollars is evaluated. Analysis indicates that the growth in NLH's normalized operating costs between 2019 actual and 2025 actual of 18% or 2.8% per year was consistent with the growth in the Consumer Price Index (CPI) of 18% or 2.8% per year and marginally below the weighted average growth in the Labour Inflator and GDP Deflator of 21% or 3.2% per year.

NLH included a $4 million productivity allowance (proposed reduction to operating costs) in its proposed 2027 Test Year operating costs, consistent with the level approved by the PUB in the 2019 Test Year. It is recommended that the PUB approve a $5 million productivity allowance for the 2027 Test Year considering the 23% escalation of costs since the last GRA and the additional future opportunities to obtain efficiencies and productivity resulting from fast advancing technology and artificial intelligence.

NLH included a $6 million vacancy allowance (proposed reduction to operating costs) in its proposed 2027 Test Year operating costs, consistent with the vacancy factor in the settlement agreement which was ultimately approved in the 2019 Test Year by the PUB. It is recommended that the PUB approve a $7 million vacancy allowance for the 2027 Test Year considering the most recent actual vacancy factor experienced by NLH in 2025.

With respect to depreciation & accretion, it is recommended that NLH provide supplemental evidence to support material changes to depreciation methodologies and depreciation expense and to bridge the gap between summary tables in the GRA filing and large technical depreciation studies when such studies are filed at future GRAs.

With respect to rate base and return on rate base, it is concluded that the $115 million proposed working capital allowance related to Muskrat Falls is reasonable for rate-setting purposes and observed that it would be beneficial to confirm the appropriate revenue requirement treatment of the $9 million of interest cost of service exclusions during the upcoming oral hearing.

In consideration of growing levels of debt at NLH, to appropriately balance the benefits and risks of variable-rate debt on behalf of ratepayers, and evaluate the prudency of proposed financing costs, it is recommended that the PUB direct NLH to file its debt management strategy and policies/guidelines for the use of variable-rate short-term debt and variable-rate long-term debt at the next GRA.

4.1 NLH's Operating Cost Growth Over the 6 Year Period between 2019 and 2025 Has Been In Line with the Consumer Price Index Increase of 18% or 2.8% Per Year

NLH asserts that its 2027 Test Year operating costs are forecast to be approximately 10% lower than the 2019 Test Year forecast in real dollars. In making this assertion, NLH has inflated the 2019 Test Year operating costs of $137 million to $173 million (28% increase) in real dollars and compared that to its 2027 Test Year forecast of $156 million in nominal dollars. NLH has calculated a $17 million ($156 million - $173 million) or 9.8% ($17 million/$173 million) decrease in operating costs in real dollars[53].

As an indicator of labour cost increases, NLH has used Statistics Canada Average Weekly Earnings for Canadian electric industries from 2019 to 2025 and its own internal labour inflation rates of 3.0% per year for the 2026 and 2027 Test Years[54]. As an indicator of non-labour cost increases, NLH has used a GDP deflator from 2019 to 2025. However, it is not clear how the 2026 and 2027 Test Years forecasts of 3.15% and 1.45% for the GDP deflator were derived[55].

There are a number of observations and concerns with respect to this approach and the calculation by NLH:

1. Test year operating costs forecasts are projections for rate-setting purposes and **actual results** will likely vary from forecast results. Assessment of performance on containing operating costs is best assessed comparing actual operating costs. Actual operating costs for 2019 were $133 million[56] or $4 million lower than the 2019 Test Year approved operating costs of $137 million[57];
2. In a future test year, revenue requirements and **rates** are **set** using **nominal dollars**, which include inflationary impacts. Real dollars are sometimes used in utility financial project assessments. However, the use of real dollars to assess performance on containing operating cost sends a confusing signal to stakeholders when the operating costs that are being proposed to be included in revenue requirements (based on nominal dollars) are expressed in real dollars;
3. A more effective approach to assessing operating cost management/containment is to consider the **actual operating cost performance** between the last GRA and the most recent actual operating cost performance in the current GRA;
4. A more **transparent approach** is to assess the actual cumulative increase in nominal operating costs against the cumulative increase in various escalation indices over the same time frame. This avoids using a mix of actual indices and internal forecasts as NLH has done;

[53] Chapter 3, Section 3.1, pg. 3.1
[54] Chapter 2, Section 2.3.1, pg. 2.30, footnote 64
[55] NP-NLH-035, footnote 1
[56] NLH 2026 GRA, Supplemental Material, Section 1.1, Chart 1-1. Pg.1
[57] Chapter 3, Section 3.1.2, Table 3-1, pg. 3.4

5. The **GDP deflator increases** of 7.8% for 2021 and 7.0% for 2022[58] (15.3% cumulative over these two years) appear to be quite generous in terms of allowance for escalation for non-labour costs. This compares to the Consumer Price Index (CPI) increases of 3.7% for 2021 and 6.4% for 2022[59] (10.3% cumulative over these two years). Using a mix of different escalation indices to evaluate cost containment performance can be beneficial with fluctuations such as those observed;
6. The 2027 Test Year operating costs that are used in the NLH calculation is net of $7 million[60] of operating costs that are added to the General Expenses Capitalized (GEC) RDA – while the 2019 Test Year operating costs do not include such an adjustment. Using a comparison of **gross operating costs** excluding the impacts of the GEC RDA is a more apples to apples assessment of NLH's operating cost containment performance over the 6-year period; and
7. Converting the cumulative nominal increases in operating costs into an **even annual increase** and comparing to the cumulative increases in escalation indices expressed as an even annual increase is a helpful metric in assessing operating cost containment performance.

The table below adjusts for the above noted observations and concerns to make an objective assessment of NLH's cost containment associated with its actual operating cost increases from 2019 to 2025.

[58] NP-NLH-035, Table 1
[59] CA-NLH-065 c, Table 1
[60] CA-NLH-067 b, Table 1

Table 4

Operating Cost Analysis - 2025 Actual vs 2019 Actual ($ Millions)					
	1	2	3 (1-2)	4 (3/2)	5
					% Even Annual
Operating Cost Component	2025 Actual	2019 Actual	$ Increase	% Increase	Increase
Labour Costs (A)	89	85	4		
Add: GEC RDA Additions (B)	6	-	6		
Normalized Labour Costs (C=A+B)	95	85	10	11.8%	1.9%
Non-Labour Costs (D)	62	48	14	29.2%	4.4%
Total Normalized Operating Costs (E=C+D)	**157**	**133**	**24**	**18.1%**	**2.8%**
				% Cumulative	% Even Annual
Escalation Metric - 2020 to 2025				**Increase**	**Increase**
Consumers Price Index (F)				17.9%	2.8%
Labour Inflator (G)				17.6%	2.7%
GDP Deflator (non-labour) (H)				25.7%	3.9%
Weighted Average (60%/40%) Labour Inflator + GDP Deflator				20.8%	3.2%

The key observations with respect to Table 4, are as follows:

1. **Labour costs** normalized/adjusted for the amounts deferred into the GEC RDA increased from $85 million[61] in 2019 to $95 million ($89 million[62] + $6 million[63]) in 2025. This is an increase of $10 million or 11.8% - which is equivalent to an even annual increase in labour costs of 1.9% per year;
2. **Non-labour costs** increased from $48 million in 2019 to $62 million in 2025[64]. This is an increase of $14 million or 29.2% - which is equivalent to an even annual increase in non-labour costs of 4.4% per year;
3. **Total normalized operating costs** increased from $133 million in 2019 to $157 million in 2025. This is an increase of $24 million or 18.1% - which is equivalent to an even annual increase of 2.8% per year;

[61] NLH 2026 GRA, Supplemental Material, Section 1.2, Chart 2-13, pg. 3
[62] NLH 2026 GRA, Supplemental Material, Section 1.2, Chart 2-13, pg. 3
[63] CA-NLH-067 b, Table 1
[64] NLH 2026 GRA, Supplemental Material, Section 1.2, Chart 2-14, pg. 4

4. The **Consumer Price Index** (CPI) increased by 17.9%[65] from 2019 to 2025 - which is equivalent to an even annual increase of 2.8% per year;
5. The **Labour Inflator** increased by 17.6%[66] from 2019 to 2025 - which is equivalent to an even annual increase of 2.7% per year;
6. The **GDP Deflator** increased by 25.7%[67] from 2019 to 2025 - which is equivalent to an even annual increase of 3.9% per year;
7. A **weighted average** of the **Labour Inflator** and **GDP Deflator** (reflecting NLH's approximate mix of 60% labour costs and 40% non-labour costs) increased by 20.8% from 2019 to 2025 - which is equivalent to an even annual increase of 3.2% per year; and
8. The above noted **even annual increases** are calculated by taking the 6th root of the cumulative increase over the 6-year period and expressing that as a percentage. For example, related to total normalized operating costs, the 6th root of 1.181 (18.1% increase) is 1.028 or 2.8% expressed as a percentage.

Based on the analysis from Table 4, the growth in NLH's normalized operating costs between 2019 and 2025 of 18.1% or 2.8% per year was consistent with the growth in CPI of 17.9% or 2.8% per year and marginally below the weighted average growth in the Labour Inflator and GDP Deflator of 20.8% or 3.2% per year.

4.2 It is Recommended That the PUB Adjust NLH's Operating Cost Productivity Adjustment from $4 Million to $5 Million for Cost Escalation Between the 2019 Test Year and 2027 Test Year

NLH is proposing net operating costs of $156 million in its 2027 Test Year revenue requirements which is comprised of gross operating costs of $163 million less deferrals to the GEC RDA of $7 million[68].

The following table summarizes the changes in operating costs between the 2027 Test Year and 2019 Test Year by major cost component – as well as before and net of GEC RDA deferrals[69]:

[65] CA-NLH-065 c, Table 1
[66] NP-NLH-035, Tables 1 and 2
[67] NP-NLH-035, Tables 1 and 2
[68] CA-NLH-068, Table 1
[69] Chapter 3, Section 3.1.2, Table 3-1, pg. 3.4

Table 5

Operating Cost Comparison - 2027 Test Year vs 2019 Test Year ($ Millions)				
	1	2	3	4
			(1-2)	(3/2)
			$	%
	2027	2019	Increase	Increase
Operating Cost Component	**Test Year**	**Test Year**	**(Decrease)**	**(Decrease)**
Labour - Gross (A)	103	85	18	21%
GEC RDA Deferrals (B)	(7)	-	(7)	
Labour - Net (C=A-B)	96	85	11	13%
System Equipment Maintenance (SEM) Costs	28	27	1	4%
Other	35	30	5	17%
Cost Allocation (Recoveries)	(3)	(5)	2	-40%
Total Operating Costs (Net of GEC RDA Deferrals) (D)	**156**	**137**	**19**	**14%**
Total Operating Costs (Before GEC RDA Deferrals) (E=D+B)	**163**	**137**	**26**	**19%**

For the 2027 Test Year, gross labour costs are forecast at $103 million before deferrals to the GEC RDA. The deferrals to the GEC RDA for 2027 are forecast at $7 million, resulting in net labour costs of $96 million[70].

On a gross basis (before deferrals to the GEC RDA) NLH's proposed operating costs for the 2027 Test Year represents an increase of $26 million or 19.0% as compared to the approved operating costs of $137 million from the 2019 Test Year.

NLH has included a $4 million productivity allowance (proposed reduction to operating costs) in its proposed 2027 Test Year operating costs in order to mitigate the growth in its operating costs for ratepayers[71]. The NLH proposed productivity allowance for the 2027 Test Year is the same amount as the $4 million productivity allowance directed by the PUB in the 2017 GRA for the 2019 Test Year[72] and as such in NLH's view is consistent with past regulatory precedent[73]. NLH clarified that this proposed productivity allowance is a self-imposed target and is not carried forward from any previous year[74].

[70] CA-NLH-067 b, Table 1
[71] Chapter 2, Section 2.4.6, pgs. 2.50 to 2.51
[72] PUB Order No. P.U. 16(2019), pg. 36
[73] CA-NLH-257
[74] CA-NLH-069 a

NLH notes that its proposed productivity allowance represents an approximately 2.5% reduction in operating costs, which is consistent with the recent productivity allowance of $2 million directed by the PUB in Newfoundland Power 2025-2026 GRA[75]. In that Newfoundland Power decision, the PUB found that a productivity allowance was necessary to incent the utility to find additional efficiencies in its operations and take additional measures to manage operating costs.

NLH was requested to explain why it did not propose a productivity allowance of greater than $4 million to account for inflation since the 2019 Test Year[76]. NLH did not directly respond to this question and instead repeated information contained in its original application.

There are a number of considerations in assessing the NLH proposed $4 million productivity allowance for the 2027 Test Year:

1. The 2019 Test Year approved operating costs was $137 million and as such, the proposed operating costs before the PUB directed productivity allowance were $141 million ($137 million + $4 million). The **PUB directed productivity allowance** of $4 million was approximately **2.8%** of proposed operating costs in the 2019 Test Year ($4 million/$141 million);
2. NLH's gross operating costs for the 2027 Test Year before the GEC RDA deferral is $163 million ($156 million + $7 million deferred to the GEC RDA). A productivity allowance of **2.8% applied** to a **gross operating cost** of **$163 million** in the 2027 Test Year would result in a $4.6 million ($163 million * 2.8%) productivity allowance;
3. NLH's gross operating expenses between 2019 actuals and the 2027 Test Year increased from $133 million to $163 million – an increase of $30 million or 22.6%. **Escalating** the $4 million **PUB directed productivity allowance** from the 2019 Test Year for expected escalation of 22.6% would result in a $4.9 million ($4 million * 1.226) productivity allowance;
4. The **escalation** in operating costs between 2019 and now has been **artificially suppressed** by a freeze in economic increases to non-union employees in the 2019 to 2022 period. NLH is signaling in its application that it is not feasible or sustainable to absorb cost pressures and has indicated that additional economic wage increases are necessary to move compensation levels closer to industry comparators;
5. **Technology** in general and artificial intelligence (AI) in particular is progressing at a fast pace. AI has been described in the news media as the 4th industrial revolution. There are significantly more opportunities and emerging technology tools for NLH to use now to obtain efficiencies and productivity than existed in the context of the NLH 2017 GRA.

[75] PUB Order No. P.U. 3(2025), pgs. 21 to 22
[76] CA-NLH-257

Based on the above noted considerations, it is recommended that the PUB approve a $5 million productivity allowance for NLH for the 2027 Test Year – towards the upper range of the illustrative calculations provided above. Considering the cost and rate pressures that were outlined in Sections 3.5 and 3.6 of this Evidence, the PUB should send a strong regulatory signal back to NLH about the need to continue to contain and appropriately manage operating costs.

The $5 million recommended productivity allowance is consistent with a 3% reduction to the proposed gross operating costs and recognizes a current/future operating environment with more opportunities to obtain efficiencies and productivity through advancing technology than was previously available in the 2017 GRA.

4.3 It is Recommended That the PUB Adjust NLH's Vacancy Allowance from $6 Million to $7 Million to Recognize NLH's Recent Actual Vacancy Rate Experience

NLH has included a $6 million vacancy allowance (proposed reduction to operating costs) in its proposed 2027 Test Year operating costs in recognition that there are on-going vacancies in any particular year. NLH indicated that the proposed vacancy allowance was calculated based on 55 FTEs in order to be consistent with the level of vacant FTEs built into the Settlement Agreement from the 2017 GRA, which was ultimately approved by the PUB[77].

The PUB requested NLH to provide the actual FTEs and vacancy factors for each year from 2019 actual to 2025 actual[78]. The response to this request for information demonstrated that NLH's actual vacancy factor from 2019 to 2025 ranged from 5.1% to 9.6% over this timeframe, with the most recent vacancy factor for 2025 being 6.8%. The average actual vacancy factor over that 7-year period is calculated as 7.3% and the average vacancy factor for the last 5-year period (excluding the high point of 9.6% in 2020) was also 7.3%.

The NLH proposed vacancy FTEs of 55 for the 2027 Test Year represents a vacancy factor of 5.9% at the gross FTE forecast for the 2027 Test Year of 937 FTEs.

NLH provided a calculation of average salary of $109,100 that is implied by its proposed FTE vacancy of 55 FTEs and proposed vacancy allowance of $6 million for the 2027 Test Year and indicated that the actual cost reduction impact of vacancies in 2024 and 2025 was $6.7 million and $6.5 million, respectively[79]. NLH indicated that at the range of vacancies between 2023 actual to 2025 actual of between 62 FTEs and 69 FTEs – the vacancy allowance for the 2027 Test Year would be an additional $760,000 (total of $6.8 million) and $1.5 million (total of $7.5 million), respectively[80] or an average of $1.1 million (total of $7.1 million) additional vacancy allowance.

[77] CA-NLH-074 b
[78] PUB-NLH-022 c, Attachment 1, pg. 1
[79] NP-NLH-047
[80] NP-NLH-143

Using the $109,100 salary per vacant FTE and actual vacancy factors of between 6.8% (most recent 2025 actual) and 7.3% (average for 2021 actual to 2025 actual) would result in total vacancy allowances for the 2027 Test Year of:

1. $7.0 million = 937 gross FTEs * 6.8% = 64 vacant FTEs * $109,100; and
2. $7.4 million = 937 gross FTEs * 7.3% = 68 vacant FTEs * $109,100.

Considering the above noted information from the record of the proceeding, it is recommended that the PUB approve a $7 million vacancy allowance for NLH for the 2027 Test Year, placing more weight to the most recent actual experience in 2025. This recommendation would equate to an approximate vacancy factor of 64 FTEs for the 2027 Test Year.

4.4 It is Recommended That NLH Be Directed to File Evidence to Bridge Between Summary Tables of Depreciation & Accretion and Comprehensive Depreciation Studies at Future GRAs

NLH is proposing depreciation & accretion (of asset retirement obligations) of $118 million in its 2027 Test Year revenue requirements which is comprised of depreciation of $117 million and accretion of $1 million[81], representing a $32 million or 37.2% increase over the $86 million approved in the 2019 Test Year.

In addition to the inclusion of this level of depreciation and accretion expenses in revenue requirements, NLH is also requesting PUB approval of the depreciation rates and methodology recommended by Concentric Energy Advisors (Concentric) in the 2023 Depreciation Study and 2024 Technical Update for inclusion in customer rates. The Concentric 2023 Depreciation Study and 2024 Technical Update span over 1,200 pages of technical depreciation material[82].

NLH was requested to provide a high-level breakdown of the $32 million proposed increase in depreciation & accretion, which is summarized in the following table[83]:

[81] Chapter 5, Section 5.2.5, Table 5-4, pg. 5.5
[82] Exhibits 7 and Exhibit 8
[83] CA-NLH2-268

Table 6

Depreciation & Accretion Comparison - 2027 Test Year vs 2019 Test Year ($ Millions)				
	1	2	3	4
			(1-2)	(3/2)
			$	%
	2027	2019	Increase	Increase
Depreciation & Accretion Component	**Test Year**	**Test Year**	**(Decrease)**	**(Decrease)**
Asset Based Growth & Disposals	80	62	18	29%
Holyrood Accelerated Depreciation Impact	29	17	12	71%
Software Asset Transfers & Additions Impact	7	2	5	250%
Asset Retirement Accretion & Other Changes	9	5	4	80%
Asset & Software Depreciation Study Changes	(7)	-	(7)	
Total Depreciation & Accretion	**118**	**86**	**32**	**37%**

The key observations with respect to Table 6, are as follows:

1. The impact of **asset based growth** and **disposals** (plant additions net of disposals) on depreciation & accretion is an $18 million increase. Capital additions to rate base between 2020 and the 2027 Test Year are approximately $1.2 billion[84];
2. The impact of the **Holyrood TGS accelerated depreciation** on depreciation & accretion is an increase of $12 million. NLH is proposing that the Holyrood accelerated depreciation in the 2027 Test Year be increased to $29 million from the $17 million previously approved by the PUB in rates and that there be no deferral of accelerated depreciation for the 2027 Test Year (actual depreciation and test year depreciation both equal to $29 million[85]);
3. The **total impact** of **asset based growth** and **disposals** and the increase in **Holyrood TGS accelerated depreciation** totals $30 million or 94% of the increase in depreciation & accretion since the 2019 Test Year;
4. Software asset transfers and additions, asset retirement accretion and **other changes** have increased depreciation & accretion by $9 million in total; and
5. The **asset depreciation study** and **software depreciation study** has decreased depreciation & accretion by $6 million and $1 million, respectively – for a total decrease of $7 million as compared to the 2019 Test Year.

[84] CA-NLH-083 a

[85] Exhibit #11, Table 1, pg. 2

Given the large magnitude (over 1,200 pages) of the depreciation study/technical update materials provided in the GRA filing, NLH was requested to provide summary explanations for the most material proposed useful life changes for a number of plant categories[86]. The most material extensions in useful life are summarized as follows, by plant category:

- **Distribution** ($2.0 million reduction to depreciation): Pole Mounted Transformers (30 to 35 years); Streetlights (20 to 25 years); Wood Poles (43 to 50 years); and Pole Cribs & Hardware (35 to 40 years);
- **Hydraulic Generation** ($1.3 million reduction to depreciation): Penstocks (70 to 80 years) and Generators-Windings (50 to 62 years);
- **General Plant** ($1.3 million reduction to depreciation): ATVs & Snowmobiles (6 to 7 years); Vehicles (6 to 7 years); Booms & Cranes (12 to 13 years); and Buildings (50 to 55 years);
- **Transmission & Distribution Lines** ($1.0 million reduction to depreciation): Ground Wire System (55 to 60 years); Wood Poles (43 to 50 years); and Pole Cribs & Hardware (35 to 40 years);
- **Computer Software** ($1.0 million reduction to depreciation): Addition of a new software category (7 to 10 years); and
- **Information Systems & Telecoms** ($0.7 million reduction to depreciation): Telecontrol System (25 to 27 years).

The vast majority (94%) of the $32 million increase in depreciation & accretion relates to the impact of net asset growth and the increase in Holyrood TGS accelerated depreciation. Net asset growth would be anticipated as a result of the passage of time since the last NLH GRA. The Holyrood TGS RDA and associated issues are addressed in Section 6.7 of this Evidence. The decrease as a result of the depreciation study/update appears to be mainly from the extension of useful lives of assets rather than changes to depreciation methodology. No significant issues were noted/outlined in the request for information process with respect to the depreciation study/technical update.

In terms of regulatory process, it is noted that the depreciation section of the GRA filing was 1.5 pages in length and the depreciation study/technical update was over 1,200 pages of detailed technical material. There does not appear to be any information on the record to bridge the paucity of depreciation material in the GRA filing - and the plethora of depreciation material in the depreciation study/technical update. The request for information process was used to attempt to bridge this gap but was only successful in obtaining the high-level analysis that is summarized in the paragraphs above.

[86] CA-NLH-90 b and CA-NLH-269

It is recommended that when future depreciation studies are filed in future GRAs – that NLH provide supplemental evidence to bridge the gap between summary tables in the GRA filing and large technical depreciation studies. This bridging evidence would highlight information such as material depreciation methodology changes and supporting rationale and material changes to depreciation expense resulting from changes to useful life estimates and supporting rationale. In addition, the bridging evidence should indicate if NLH adopts the methodology and useful life changes recommended by the external consultant with supporting rationale or the supporting rationale if NLH does not adopt these recommendations.

4.5 The Calculation of the $115 Million of Working Capital Allowance Related to Muskrat Falls and Included in the Proposed 2027 Test Year Rate Base is Reasonable

NLH is proposing an average rate base of $2.802 billion[87] in its 2027 Test Year revenue requirement, representing a $485 million or 20.9% increase over the $2.317 billion rate base approved in the 2019 Test Year.

The following table provides a breakdown of the components of the proposed rate base for the 2027 Test Year and a comparison to the approved 2019 Test Year.

Table 7

Average Rate Base Comparison - 2027 Test Year vs 2019 Test Year ($ Millions)				
	1	**2**	**3**	**4**
			(1-2)	**(3/2)**
			$	**%**
	2027	**2019**	**Increase**	**Increase**
Rate Base Component	**Test Year**	**Test Year**	**(Decrease)**	**(Decrease)**
Average Capital Assets	2,457	2,122	335	16%
Working Capital Allowance - Muskrat Falls	115	-	115	
Working Capital Allowance - Other	2	2	-	0%
Fuel Inventory & Materials and Supplies	113	90	23	26%
Deferred Charges	115	103	12	12%
Total Average Rate Base	**2,802**	**2,317**	**485**	**21%**

Other than the increase in average capital assets, the only other increase in the proposed rate base for the 2027 Test Year that results in a material increase in proposed rate base and

[87]Chapter 5, Section 5.3, Table 5-7, pg. 5.11

associated revenue requirements is the new addition of working capital allowance related to the in-service of the Muskrat Falls Assets.

The **Muskrat Falls working capital allowance** has been calculated by NLH at $115 million using a lead/lag approach to derive the proposed additional working capital allowance. NLH indicates that the inclusion of this $115 million of working capital allowance increases the proposed 2027 Test Year revenue requirements by $6.2 million[88]. NLH's calculation of the Muskrat Falls working capital allowance is summarized as follows:

1. **Muskrat Falls Revenue Lag Days**: NLH has calculated a Muskrat Falls revenue lag of 44.5 days[89]. The primary components of this revenue lag are (i) rate mitigation funding revenue lag of 36 days assuming that rate mitigation funding is paid monthly at the same lag as Newfoundland Power (weighted at 86%) and (ii) monetization revenue lag of 183 days assuming this revenue is paid in January of the subsequent year (weighted at 7%);
2. **Muskrat Falls Expense Lag Days**: NLH has calculated a Muskrat Falls expense lag of 7.8 days (net)[90]. The primary components of this expense lag are (i) Muskrat Falls Supply Costs expense lag of 13.8 days based on contractual requirements that these costs are paid upon the first day of the month in advance of benefit of the supply costs being received (weighted at 97%) and (ii) export costs expense lead of 182.5 days assuming this expense is paid in January in the following year similar to the assumption on export revenues (weighted at 3%);
3. It is noted that **expense items** are **usually leads** in lead/lag studies as expenses are usually paid after the service is received. In the case of the Muskrat Falls Supply Costs – there is an expense lag as these expenses are paid in advance of the benefits of these costs being received; and
4. **Muskrat Falls Working Capital Allowance:** The $115 million of average Muskrat Falls working capital allowance is then calculated as $806 million of Muskrat Falls Supply Costs and export costs times a total lag of 52.2 days (44.5 days + 7.8 days) and divided by 365[91].

It appears that the calculation of the Muskrat Falls working capital allowance for the 2027 Test Year is reasonable, relying on NLH's representations with respect to the Muskrat Falls contractual arrangements, based on the above-noted calculations and common utility practice with respect to lead/lag methodologies.

[88] Chapter 5, Section 5.3, pg. 5.13
[89] PUB-NLH-098, Attachment 1, pg. 2
[90] CA-NLH-264, Attachment 1, pg. 1
[91] PUB-NLH-098, Attachment 1, pg. 1

4.6 It Would Be Beneficial if the Appropriate Regulatory Treatment of the $9 Million of Interest Cost of Service Exclusions is Confirmed During the Upcoming Oral Hearing

NLH is proposing a total return on rate base of $137 million[92] in its 2027 Test Year revenue requirement, comprised of regulated interest of $73 million and regulated net income of $64 million[93]. This represents an $11 million or 8.7% increase over the $126 million total return on rate base approved in the 2019 Test Year.

The table below provides the components of total return on rate base and the changes in the 2027 Test Year as compared to the 2019 approved Test Year.

Table 8

Return on Rate Base Comparison - 2027 Test Year vs 2019 Test Year ($ Millions)				
	1	**2**	**3**	**4**
			(1-2)	**(3/2)**
			$	**%**
Return on Rate Base Component	**2027 Test Year**	**2019 Test Year**	**Increase (Decrease)**	**Increase (Decrease)**
Interest & Debt Guarantee Fees (A)	113	97	16	16%
Interest Cost of Service Exclusions (B)	(9)	(7)	(2)	29%
Finance Charges (C=A-B)	104	90	14	16%
Interest During Construction (D)	(23)	(2)	(21)	
Interest on Regulatory Deferral Accounts (E)	(8)	1	(9)	
Regulated Interest (F=C+D+E)	**73**	**89**	**(16)**	**-18%**
Net Income per Financial Forecast (G)	55	27	28	104%
Interest Cost of Service Exclusions (H)	9	7	2	29%
Depreciation Exclusions (I)	-	3	(3)	
Regulated Net Income (J=G+H+I)	**64**	**37**	**27**	**73%**
Total Return on Rate Base (K=F+J)	**137**	**126**	**11**	**9%**

The key observations with respect to Table 8, are as follows:

1. **Finance charges** (net of interest cost of service exclusions)[94] have increased by $14 million since the 2019 approved Test Year from $90 million to $104 million, primarily as a result

[92] Chapter 5, Section 5.5, Table 5-11, pg. 5.11
[93] CA-NLH-096 c
[94] Schedule D-IV, pg. 1

of a $728 million increase in average debt ($2.563 billion - $1.835 billion[95]) but somewhat offset by a decrease in the embedded cost of debt from 4.91% to 4.05%;

2. **Regulated interest** has decreased by $16 million from $89 million in the 2019 Test Year to $73 million in the 2027 Test Year primarily as a result of a $21 million increase in interest during construction[96] due to higher capital construction, partially offset by the increase in finance charges noted above;
3. **Regulated net income** is calculated by NLH as the net income per the financial forecast and then adding back interest cost of service exclusions and depreciation exclusions[97]. Regulated net income has increased by $27 million from $37 million in the 2019 Test Year to $64 million in the 2027 Test Year; and
4. **Total return on rate base** has increased by $11 million from $126 million in the 2019 Test Year to $137 million in the 2027 Test Year. The $11 million increase results from (i) an increase of $26 million resulting from an increase in rate base ($2.802 billion - $2.317 billion = +$485 million * 5.43%) and (ii) a decrease of $15 million resulting from a decrease in the overall rate of return (4.88% - 5.43%[98] = -0.55% * $2.802 billion).

Normally, total return on rate base calculations are relatively straightforward in that average rate base is multiplied by the overall rate of return to derive the total return on rate base. The NLH calculations to derive the total return on rate base as summarized in Table 8 above, are somewhat convoluted. However, the more standard calculation of total return on rate base, based on an average rate base of $2.802 billion * an overall rate of return of 4.88% - appears to reconcile to the proposed total return on rate base of $137 million for the 2027 Test Year.

NLH indicates that the net of interest cost of service exclusions are primarily related to a disallowed portion of the debt guarantee fees and has provided a calculation of total debt guarantee fees of $10.6 million and disallowed debt guarantee fees of $8.8 million, for net recoverable portion of debt guarantee fees of $1.8 million for the 2027 Test Year[99].

NLH was requested to explain if the interest cost of service exclusions of $8.8 million for the 2027 Test Year (rounded to $9 million in Table 8 above) are included in proposed revenue requirements and rates[100]. In response, NLH indicated that the $8.8 million of interest cost of service exclusions are added back in the return on rate base calculations as "it was included in net income". NLH also asserted that the $8.8 million is excluded from revenue requirements and not recovered from ratepayers – and produced a table showing that the $8.8 million interest cost of service exclusion was removed from the calculation of regulated interest and added to the

[95] Schedule D-IV, pg. 1
[96] Schedule D-II, pg. 6
[97] Schedule D-II, pg. 4
[98] Schedule D-II, pg. 4
[99] PUB-NLH-072, Attachment 1, pg. 1
[100] CA-NLH-096 c and CA-NLH-271, Attachment 1, pg. 1

calculation of regulated net income. These calculations had the "appearance" that the $8.8 million interest cost of service exclusion continued to be in revenue requirements (and rates) and had just been reclassified from regulated interest to regulated net income.

In reviewing the record on the appropriate regulatory treatment of the $8.8 million interest cost of service exclusion it appears that the full $10.6 million of debt guarantee fees have been deducted in calculating the approximate $55 million of net income per the financial forecast. It is interpreted that if the $8.8 million interest cost of service exclusion is not added back in the calculation of regulated net income – then the impact would be that this exclusion has been disallowed twice, (i) once in calculating regulated interest and (ii) a second time in calculating regulated net income.

Based on this interpretation, it appears that NLH's calculation of total return on rate base reflects an appropriate treatment of the $8.8 million interest cost of service exclusion. It would be beneficial if this interpretation was confirmed during the upcoming oral hearing process.

4.7 It is Recommended That NLH Be Directed to File Its Debt Management Strategy and Guidelines for the Use of Variable-Rate Debt with the PUB at the Next GRA

The following provides a comparison of the NLH debt portfolio between the 2027 Test Year and 2019 approved Test Year[101]:

Table 9

Debt Portfolio Comparison - 2027 Test Year vs 2019 Test Year ($ Millions)						
	1	2	3	4	5	6
			(1-2)	(3/2)		
					%	%
					Debt	Debt
			$	%	Portfolio	Portfolio
	2027	2019	Increase	Increase	2027	2019
Debt Portfolio Component	**Test Year**	**Test Year**	**(Decrease)**	**(Decrease)**	**Test Year**	**Test Year**
Total Debentures (A)	2,725	1,825	900	49%	93%	86%
Promissory Notes (B)	216	292	(76)	-26%	7%	14%
Total Debt Portfolio (C=A+B)	2,941	2,117	824	39%	100%	100%
Sinking Funds (D)	(214)	(237)	23	-10%		
Other (E)	12	12	-	0%		
Total Debt (F=C-D+E)	**2,739**	**1,892**	**847**	**45%**		

[101] Schedule D-IV, pg. 1

The key observations with respect to Table 9, are as follows:

1. NLH's **total debt** has increased by $847 million between the 2019 Test Year and 2027 Test Year, an increase of 44.8%;
2. Total **long-term debentures** have increased by $900 million between the 2019 Test Year and 2027 Test Year;
3. **Promissory notes** have decreased by $76 million between the 2019 Test Year and 2027 Test Year; and
4. The **proportion** of **long-term debentures** in the debt portfolio has increased from 86% in the 2019 Test Year to 93% in the 2027 Test Year and the **proportion** of **short-term promissory notes** in the debt portfolio has decreased from 14% in the 2019 Test Year to 7% in the 2027 Test Year.

As was previously noted in Section 3.2 of this Evidence, short-term variable rate debt and long-term variable-rate debt represents 0% of NLH's total debt portfolio in the 2027 Test Year, as the utility is focused on limiting its exposure to variable interest rate fluctuations. Further, NLH does not have a prescribed target and percentage allocation or standalone limit for variable-rate debt and it was not aware of a PUB review of its debt management strategies at a prior GRA proceeding.

During the request for information process[102], NLH confirmed that its promissory notes are generally issued for a specified short-term maturity, typically 30 days or less and are priced at a market-based interest rate agreed with the lender at the time of issuance, which does not reset during the term of the note. NLH also confirmed that the borrowing rate for its credit-facility borrowings is based on the applicable term CORRA rate for the selected interest period plus the appropriate credit spread, which does not reset during the interest rate period (unless it is renewed or continued for a subsequent interest period). NLH also provided summaries of the terms and conditions of its promissory note program and committed credit facility[103] which indicated limits of $300 million and $600 million, respectively – for total short-term borrowing facilities of $900 million.

Given that the applicable interest rates for these short-term borrowings (promissory note program and committed credit facility) are influenced by prevailing short-term market rates at the time of pricing, NLH considers that they have "variable-rate characteristics". NLH indicates that for the purposes of its 2027 Test Year, it has assumed a short-term borrowing rate of 2.78%, inclusive of the applicable borrowing spread. NLH was unable to provide an estimate of the cost

[102] CA-NLH-272
[103] CA-NLH-273

of issuing variable-rate long-term debt as this was not contemplated in its 2027 financial forecast[104].

NLH's debt portfolio has grown significantly (increase of 45% since the 2019 Test Year) and will continue to grow as a result of the significant increase in the capital expenditure program. Regulated utilities usually have some exposure to both short-term variable-rate debt and long-term variable-rate debt at typically lower interest rates in order to meet the objective of a reasonable cost debt portfolio. At the same time, the potential benefit of lower interest costs is balanced against the risk of variable-rate debt through the development of debt management strategies and associated policies and guidelines for targets and limits of variable-rate debt.

Review of the debt management strategies and associated policies and guidelines for targets and limits of variable-rate debt at GRAs is an important consideration for regulators to determine the prudency of the financing costs to be approved in revenue requirements.

It is recommended that the PUB direct NLH to develop and file its debt management strategies and variable-rate debt guidelines at the next GRA for the review of the prudency of these strategies and guidelines and in consideration of the growing debt portfolio at NLH.

[104] CA-NLH-274

5.0 There is a Recommended Adjustment and Outstanding Concerns Related to NLH's Update of Its Intercompany Transactions Costing Guidelines (ITCG)

This Section of the Evidence evaluates NLH's update and proposed changes to its Intercompany Transactions Costing Guidelines (ITCG) that are used to allocate over $34 million of shared service costs between its regulated operations and non-regulated operations.

A comprehensive review of the reasonableness of the ITCG in the 2026 GRA is important, given the passage of time since the last PUB review (2013 GRA), recent changes in NLH's corporate structure and potential for cross subsidization between regulated and non-regulated operations.

A prudency review of the underlying shared service costs is undertaken by the PUB to determine that these costs are both necessary and prudent. There is an outstanding issue regarding the prudency of net administration fees allocated from non-regulated operations.

NLH is proposing two methodological changes to the ITCG, including transitioning to a one-step allocation approach in order to allocate administrative business unit costs and to remove administrative business unit components from allocator calculations. These proposed changes are practical, remove unnecessary complexity/false precision, improve the administrative simplicity and the transparency and traceability of the resulting allocations of shared service costs. They are recommended for approval by the PUB.

The third methodology change to the ITCG that NLH is proposing is to introduce a 2-factor hybrid allocator (50% equal weightings to gross PPE and O&M costs) to allocate governance costs (executive, corporate secretary, communications and safety, health & environmental shared service costs). This proposed change is directionally an improvement as these types of shared service costs are more appropriately allocated using composite allocators that reflect the size, scale, scope and complexity of the operating units of the utilities. It is recommended that the PUB accept this change for the purposes of the 2026 GRA (setting rates for the 2027 Test Year).

It is also recommended that the PUB direct NLH to re-evaluate the inclusion of revenue and development of a 3-factor composite allocator to allocate these governance costs and report on this re-evaluation for its next GRA.

NLH is proposing to continue to allocate three cost pools of information technology (IT) costs based on an average users cost allocator, with a 57% allocation to regulated operations. The use of a functional allocator (average users) is counterintuitive considering the diverse range of underlying IT services/costs and how modern IT systems function and are priced by vendors. Using a cost allocator that includes a weighting of the benefits of this diverse IT infrastructure on the basis of size, scale and scope of the operating units of NLH is appropriate. It is recommended that the PUB approve a cost allocator for IT costs that is weighted 50% to FTEs and 50% to NLH's proposed 2-part hybrid allocator (capital and operating) to improve cost causation and simplify the allocations. This recommendation would reduce the proportion of the IT allocation to regulated operations to 44% and 2027 Test Year revenue requirements by $2.6 million.

5.1 NLH's Revised Intercompany Transactions Costing Guidelines (ITCG) Allocate Over $34 Million of Shared Service Costs & Have Not Been Reviewed by the PUB Since the NLH 2013 GRA

NLH uses its Intercompany Transactions Costing Guidelines (ITCG) to allocate shared service costs between its regulated operations and non-regulated operations/lines of business. Shared service costs include human resources, information systems, operating technology, safety, health & environment, procurement, building & office services, accounts payable, general ledger, corporate secretary, executive and culture & employee engagement[105].

In 2026, NLH reviewed and revised its ITCG and associated internal cost allocation methodologies in response to the passage of time and corporate structure changes arising from the amalgamation of it and its former parent company, Nalcor Energy, on January 1, 2025.

NLH engaged KPMG to undertake a comprehensive review of the revised ITCG and provide a report for filing with the 2026 GRA (KPMG Report)[106]. In addition, the PUB engaged Doane Grant Thornton (DGT) to review and report on three aspects of the changes to the ITCG: (i) introduction of a hybrid allocator, (ii) transition from a partial two-step allocation approach to a one-step allocation approach and (iii) removal of administrative business unit components from allocator calculations (DGT Report)[107].

Information in the KPMG Report indicates that the shared service costs allocated between regulated and non-regulated operations have more than doubled since 2019, increasing from $16.7 million in 2019 to $29.0 million in the 2025 budget and $34.4 million in the 2026 forecast[108].

NLH is proposing that the net administration fees (non-regulated administration fees charged to regulated operations less regulated administration fees charged to non-regulated operations) charged through the ITCG and included in operating costs increase to $4.7 million in the 2027 Test Year, from $2.8 million approved in the 2019 Test Year (an increase of $1.9 million or 67.9%)[109].

The non-regulated administration fees charged to regulated operations have increased by $5.1 million between the 2019 Test Year and 2027 Test Year, mainly as a result of higher Information Systems charges ($3.5 million of the increase) and other changes to the ITCG ($2.1 million of the increase)[110].

The regulated administration fees charged to non-regulated operations have increased by $3.2 million between the 2019 Test Year and 2027 Test Year, mainly as a result of the transfer of shared information systems and business system assets and projects to regulated operations

[105] Chapter 3, Section 3.1.2, pgs. 3.8 and 3.9
[106] Exhibit 2, Attachment 2: KPMG Intercompany Transactions Costing Guidelines Review Report (KPMG Report)
[107] Information Item #5, Doane Grant Thornton Report (DGT Report), Section 1.1, pg. 1
[108] KPMG Report, Section 5.4, Table 36, pg. 38
[109] Chapter 3, Section 3.1.2, Table 3-3, pg. 3.7
[110] PUB-NLH-026, Attachment 1, pg. 1 and CA-NLH-351 b

($1.4 million of the increase) and the addition of new shared service groups ($1.5 million of the increase)[111].

The last comprehensive regulatory review of the NLH ITCG by the PUB occurred in the 2013 GRA, approximately 13 years ago[112].

It is important that the ITCG undergo a comprehensive review in the 2026 GRA, given the passage of time since the last PUB review, the infrequency of regulatory review, recent changes in NLH's corporate structure, the regulatory sensitivity to potential cross subsidization between regulated and non-regulated operations and the increasing pool of shared service costs to be allocated.

5.2 The Prudency of the Underlying Shared Service Cost Allocations is a Distinct Issue from the Appropriateness of the ITCG Allocation Methodologies

In reviewing NLH's operating costs for potential approval into the 2027 Test Year revenue requirements, the PUB is assessing if the costs are necessary and prudent.

It is important to distinguish that (i) the PUB's review of the prudency of the underlying shared service costs and (ii) the PUB's review of the reasonableness of the framework and internal cost allocation methodologies (inherent in ITCG). These are two distinct issues or regulatory tests that the PUB undertakes to determine that the allocated shared service costs are both necessary and prudent.

It is clear that neither the scope of the KPMG Report nor the scope of the DGT Report was to assess the prudence, necessity or reasonableness of the underlying shared service costs being allocated, evaluate the overall level of NLH's shared service costs or complete any benchmarking to assess shared service costs against other peer utilities[113]. The opinions expressed in both reports relate solely to the internal cost allocation methodologies under review.

When requested to explain how the PUB can assess the prudency of the underlying shared service costs, NLH indicated that this could be accomplished through its review of the proposed 2027 Test Year revenue requirements[114]. When requested to explain how the PUB can assess the prudency of shared-service costs initially recorded in non-regulated operations but subsequently charged or allocated to regulated operations, NLH did not directly respond to the concern that these costs may not form part of the 2027 Test Year revenue requirements[115].

NLH indicated that employees hired within the corporate services departments are expected to provide services to both regulated operations and non-regulated operations and as such these

[111] PUB-NLH-026, Attachment 1 and CA-NLH-351 a
[112] KPMG Report, Section 2.2, pg. 7
[113] KPMG Report, Executive Summary, pg. 3 and GDT Report, Section 1.5, pg. 2
[114] CA-NLH-213 b
[115] CA-NLH-344

shared service employees are by default assigned to a non-regulated business unit[116]. As such, it does not appear that the shared service staff that are designated as being part of a non-regulated business unit would be part of the labour costs that are included in the 2027 Test Year revenue requirements. It is also not clear if other non-labour costs related to these shared service functions in non-regulated business units are included in the 2027 Test Year revenue requirements.

Based on a review of the record of this proceeding, there does not appear to be sufficient information to assess how much of the various categories of the over $34 million shared service costs are contained in the other sub-components of operating costs that are subject to review in the 2027 Test Year revenue requirements – and those categories of shared services costs that are not included in 2027 Test Year revenue requirements and only allocated to regulated operations through the net administration fee sub-component of operating costs. Shared service costs that are not part of the 2027 revenue requirements and only allocated to regulated operations through the net administration fee sub-component of operating costs – have not undergone a prudency review in this regulatory proceeding.

Given the foregoing, the prudency review of the underlying shared service costs is an outstanding issue that should be further explored in the upcoming oral hearing related to this proceeding.

5.3 Transitioning to a One-Step Allocation Approach & Removal of Administrative Business Unit Components from Allocator Calculations are Reasonable and Should be Approved by the PUB

As briefly noted above in Section 5.0 of this Evidence, two of the methodology changes that NLH is proposing as part of the update of its ITCG are (i) transition from a partial two-step allocation approach to a one-step allocation approach and (ii) removal of administrative business unit components from allocator calculations.

Transition from a Partial Two-Step Allocation Approach to a One-Step Allocation Approach

Under the former ITCG methodology, the use of a partial two-step approach allocates certain administrative costs among the administrative business units themselves as a first step (as the administrative business units also provide services to one another), before allocating the resultant costs to regulated operations and non-regulated operations[117].

NLH is proposing to move to a one-step approach which allocates administrative business unit costs directly to regulated operations and non-regulated operations in a single step. NLH's rationale to move to the one-step approach is that it provides greater simplicity and improved traceability of costs from the originating administrative business unit to the final line of business.

[116] CA-NLH-212 b

[117] DGT Report, Section 3.3, pgs. 9 to 12

This proposed ITCG methodology change is estimated to decrease shared service cost allocation to regulated operations in the 2027 Test Year by approximately $219,000[118].

Removal of Administrative Business Unit Components from Allocator Calculations

Shared service costs are allocated to NLH's lines of business using cost allocators built from operational measures such as FTEs. Given that administrative functions themselves also generate these same measures (such as FTEs) – the staff and activities of the administrative functions can be captured within the very allocators that are used to allocate these administrative costs – and as such can influence the resulting split of shared service costs between regulated operations and non-regulated operations (under the former ITCG methodology). NLH's former ITCG methodology was to include administration functions in the allocators. KPMG noted that administrative fees were being allocated between each other and back to themselves[119].

NLH is proposing to remove administrative business unit components from allocator calculations. NLH's rationale for this change is to remove the bias resulting from inclusion of administrative functions in the allocators. This proposed ITCG methodology change is estimated to increase shared service cost allocation to regulated operations in the 2027 Test Year by approximately $617,000[120].

These Two ITCG Methodology Changes are Reasonable

DGT concluded that the transition to the one-step allocation methodology is reasonable, improves the transparency, traceability and administrative simplicity of the shared service allocation process and is immaterial in its impact[121]. KPMG noted that the impact of this transition was negligible[122].

DGT highlighted a potential distortion related to the inclusion of administrative business unit components in the allocator calculation in that the inclusion of the shared service provider's own amounts in the cost allocators does not reflect the benefit received by the operating line of business that consumes the shared service and permits an internal designation to impact the allocation[123].

DGT concluded the removal of administrative business unit components from allocator calculations was reasonable, notwithstanding the increased allocation to regulated operations – and that this change produces allocators that more accurately reflect the consumption of administrative services by the operating lines of business, consistent with the principle of cost

[118] DGT Report, Section 3.3.3, pgs. 11 and 12
[119] KPMG Report, Section 5.3.1, pg. 19 and CA-NLH-216
[120] DGT Report, Section 3.4, pgs. 12 and 13
[121] DGT Report, Section 6.5, pg. 29
[122] CA-NLH-216
[123] DGT Report, Sections 7.2 and 7.3, pgs. 31 to 32

causation and maintains consistency across the affected allocators[124]. KPMG considers that this proposed change improves objectivity, removes the administrative-location effect and is better aligned with the cost-causality principle at the methodological level[125].

Additionally, DGT assessed the materiality of the combined impact of these two changes to the ITCG as an additional allocation to regulated operations of $0.4 million as being minimal[126].

A commonly used framework for assessing the reasonableness of rate proposals in the context of public utility rate-regulation is to consider proposals from three perspectives[127]:

1. Revenue-related attributes of ratemaking of revenue sufficiency, rate stability and rate predictability;
2. Cost-related attributes of ratemaking of cost-causation, fairness, equity and efficiency; and
3. Practical-related attributes of ratemaking such as practicality, administrative simplicity and general acceptance.

In respect to these two proposed changes to the ITCG methodology, the primary considerations are the cost-related attribute of cost-causation and the practical-related attributes.

It does not appear that complex and somewhat circular allocations of administrative business unit costs between themselves and inclusion of administrative business units' factors into the calculation of cost allocation drivers used to allocate those very shared service costs improves cost causation and may result in potential distortions to the resulting allocations.

These two proposed changes to the ITCG methodology are practical, remove unnecessary complexity/false precision, improve the administrative simplicity and the transparency and traceability of the resulting allocations of shared service costs.

On the basis of cost-causation and practical-related attributes of ratemaking and considering that the net impact of these changes is relatively immaterial, these two changes to the ITCG methodology are reasonable and should be approved by the PUB.

[124] DGT Report, Section 7.7, pg. 34
[125] CA-NLH-216
[126] DGT Report, Section 8.3, pg. 35
[127] James C. Bonbright et al, Principles of Public Utilities Rates, 2nd Edition, Public Utilities Reports, Inc. (1988), pgs. 383 to 384

5.4 It is Recommended That the PUB Direct NLH to Revisit the Merits of a 3-Factor Hybrid Allocator to Include Revenue at the Next GRA when Churchill Falls Renegotiations are Complete

The third methodology change to the ITCG that NLH is proposing is to introduce a "Hybrid Allocator" for allocating the shared service costs related to executive, corporate secretary, communications and safety, health & environmental functions[128]. NLH is proposing a 2-factor hybrid allocator with equal 50%/50% weightings to (i) gross property, plant & equipment (PPE) and (ii) operating & maintenance (O&M) costs. The above noted shared service costs are proposed to be allocated to each line of business based on their relative proportion of this 2-factor allocator[129].

For the 2027 Test Year, the calculation of this hybrid allocator results in the allocation of 30% of the above-noted shared service costs to regulated operations. The 30% allocation to regulated operations is calculated based on equal 50% weightings of (i) 20% for gross PPE and (ii) 40% O&M[130]. The proposed hybrid allocator results in the allocation of 70% of the above-noted shared service costs to non-regulated operations based on equal 50% weightings of (i) 80% for gross PPE and (ii) 60% for O&M.

The 2026 forecast pool of costs for the above-noted shared service costs is approximately $4.1 million, with $1.2 million proposed to be allocated to regulated operations and $2.9 million allocated to non-regulated operations[131].

The DGT Report describes a hybrid allocator as a blended measure for shared service functions that provide broad support to the organization as a whole and are not readily associated with a single operational driver such as headcount. Where no single cost driver adequately reflects the cause of the cost or the benefit received, a blended or multi-factor allocator may be reasonable, provided the selected factors together offer a supportable measure of relative scale, benefit or cost responsibility[132].

A summary of DGT's evaluation of NLH's proposed 2-factor hybrid allocator is as follows[133]:

1. There is a reasonable basis for selecting gross PPE and O&M to allocate functions that support the organization as a whole, as relative scale is a defensible proxy for these functions. PPE reflects the size of the capital base and O&M costs reflect the scale of operational activity;
2. Weighting involves judgement, and an equal weighting provides a neutral and readily understandable means of combining the two measures in the absence of evidence supporting a greater emphasis on one factor over the other; and

[128] DGT Report, Section 1.1, pg. 1
[129] DGT Report, Section 5.3, pgs. 20 to 23
[130] CA-NLH-214 c
[131] DGT Report, Section 3.2, Table 3-2, pg. 8
[132] DGT Report, Section 5.2, pgs. 19 to 20
[133] DGT Report, Section 5.3.1, pg. 20, Section 5.3.2, pg. 22 and Section 5.3.3, pgs. 22 to 23

3. The proposed hybrid allocator performs well in terms of evaluation criteria of transparency, objectivity and administrative practicality.

The DGT Report and KPMG Report[134]both indicate that considering utility industry practice, revenue represents the most common additional component in composite allocators (another name for hybrid allocators) of this kind. Such 3-factor composite allocators are generally calculated using (i) a revenue metric (ii) PPE/capital assets metric and (iii) a labour metric. This 3-factor composite allocator is generally referred to as the "Massachusetts Formula" and is a commonly used approach by Canadian and US utilities to allocate shared service costs where specific allocators are not considered reflective of the underlying cost drivers. DGT and KPMG both note that NLH considered the use of the Massachusetts Formula but that NLH had identified concerns with this approach.

NLH's concerns are that the inclusion of revenue in the hybrid allocator may result in distortion of the allocations as a result of [135]:

1. Electricity rates associated with the Churchill Falls contract are lower than prevailing market rates; and
2. Intercompany transactions such as Muskrat Falls and Labrador-Island Link revenue and revenue earned from the sale of intercompany revenue to third parties.

DGT agreed with NLH that the exclusion of revenue was reasonable based on these concerns[136].

In the request for information process, NLH was requested to identify comparable utilities with regulated and non-regulated operations that use revenue as a component of a 3-factor shared service cost allocator and explain how these utilities have dealt with intercompany revenues and non-market contract prices[137]. NLH did not directly respond to this request for information and simply repeated cross references to the KPMG Report and DGT Report.

NLH was also requested to provide an illustrative calculation of the impact to the 2027 Test Year shared service cost allocations assuming a 3-factor hybrid/composite allocator, including revenue in addition to gross PPE and O&M in both rounds of request for information[138]. NLH refused to provide such an illustrative calculation as it had not determined an appropriate revenue measure and it does not consider inclusion of revenue to be appropriate.

[134] DGT Report, Section 5.3.1.2, pgs. 21 to 22 and KPMG Report, Section 5.3.2, pg. 22
[135] CA-NLH-214 b
[136] DGT Report, Section 5.3.1.2, pgs. 21 to 22
[137] CA-NLH-345
[138] CA-NLH-214 d and CA-NLH-347

NLH's Proposal to Transition to a 2-Factor Hybrid Allocator is a Directional Improvement

NLH's proposed change to the ITCG to introduce a hybrid allocator for allocating the shared service costs related to executive, corporate secretary, communications and safety, health & environmental functions is directionally an improvement over the prior methodology of using specific functional cost drivers (such as FTEs and timesheets) to allocate these costs between regulated operations and non-regulated operations. Functional cost drivers involve the use of a single metric to allocate common costs.

Hybrid or composite cost allocators involve the weighting of more than one functional allocator to allocate shared service costs. A hybrid cost driver more appropriately recognizes that from the perspective of cost causation that these indirect shared service costs do not have a direct correlation with any particular (functional) cost causation driver.

For these indirect shared service costs, hybrid or composite allocators are commonly used in the utility sector, which generally reflect the size, scale, scope and complexity of the operating units of the utilities and the capital-intensive and labour-intensive nature of utility operations. Hybrid or composite cost allocators also reduce the risk of heavy or sole reliance on a single metric to allocate common costs.

Potential Inclusion of Revenue in a 3-Factor Composite Allocator

Despite the directional improvement to move to a 2-part hybrid cost allocator to allocate these costs, the outstanding issue relates to the common practice across regulated utilities of using 3-factor composite cost allocators (Massachusetts Formula) – which also include a measure of revenues as the 3rd part of the composite allocator.

The 3-factor composite cost allocators best reflect the size, scale, scope and complexity of the operating units of regulated utilities and the nature of the shared service costs that are proposed to be allocated by the hybrid allocator. The 3-part composite cost allocators also best meet the evaluation criteria of flexibility/adaptability of the ITCG that was outlined in both the DGT Report and KPMG Report[139]. The 3-factor Massachusetts Formula is more flexible to deal with business and operational changes and is more stable as there is less risk of reliance on only one or two functional allocators (less weighting to each metric in a 3-factor allocator).

The KPMG Report notes that ENMAX uses a "Universal Allocator" 3-factor composite allocator and that Manitoba Hydro/Centra Gas use a 2-part allocator (corporate assets and labour activity charges)[140]. It is noted that the Manitoba Public Utilities Board has recently directed that Manitoba Hydro/Centra Gas move to a 3-factor composite allocator (equal weighting of revenue, corporate assets and labour activity charges), which includes net export revenues[141].

[139] DGT Report, Section 4.2, pg. 16 and KPMG Report, Section 3.4, pg. 13
[140] KPMG Report, Section 4.2. pg. 15 and Section 4.3, pg. 16
[141] Manitoba PUB Order 120/25, pgs. 85 to 89

Additionally, it is also noted that ATCO and EPCOR use 3-factor composite allocators, as well as a number of Canadian gas utilities.

In terms of NLH's concerns with respect to the inclusion of revenues in a 3-factor composite allocator, the existence of intercompany transactions and export revenues is a common feature of the utility business and should not in and of themselves result in the exclusion of revenues from the composite allocator. The fact that electricity rates associated with the Churchill Falls contract are lower than prevailing market rates is a valid concern. There may be movement on this issue based on the DCIA recently signed between NLH and Hydro-Quebec. However, these negotiations are still ongoing and will not be finalized for the purposes of this GRA proceeding.

Recommendations on the 2-Factor Hybrid Allocator for the 2027 Test Year

Based on the foregoing analysis, it is recommended that the PUB accept NLH's proposal to move to a 2-factor hybrid cost allocator for the above-noted shared service costs for the purposes of the 2026 GRA (setting rates for the 2027 Test Year).

It is also recommended that the PUB direct NLH to re-evaluate the inclusion of revenue and development of a 3-factor composite allocator for these shared service costs and report on this re-evaluation for its next GRA. This re-evaluation would consider the outcome of re-negotiations of the Churchill Falls contract.

5.5 It is Recommended That the PUB Approve a Cost Allocator for IT Costs that is 50% Weighted to FTEs and 50% Weighted to the Proposed NLH Hybrid Allocator to Improve Cost Causation

As part of its ITCG, NLH is proposing to continue to allocate three cost pools of information technology (IT) costs (i) information services, (ii) network services and (iii) business system transformation program based on an average number of users or "average users" cost allocator[142]. The three IT cost pools total $19.8 million, which represent approximately 58% of total shared service costs of $34.4 million for the 2026 forecast[143].

NLH Proposes to Allocate IT Cost Pools 57% to Regulated & 43% to Non-Regulated Operations

Information systems costs relate to the IT help desk, PC/device deployment, IT project management, enterprise architecture, system management, application development, cyber security, information management and standards/policy management[144]. Network services costs relate to maintenance of the LAN and phone networks[145]. Business system transformation program costs relate to migration of the ERP system from JD Edwards World to JD Edwards

[142] Exhibit 2, Attachment 1, Section 3.1, Table 1, pg. 3
[143] KPMG Report, Section 5.4, pg. 38
[144] KPMG Report, Section 5.3.3.2, pg. 25
[145] KPMG Report, Section 5.3.3.6, pg. 31

EnterpriseOne and implementation of planning, budgeting and forecasting solution Cognos TM1[146].

For the 2027 Test Year, the use of the average user cost allocator results in the allocation of approximately 57% of the three IT cost pools to regulated operations and 43% to non-regulated operations[147], with $11.6 million proposed to be allocated to regulated operations and $8.2 million allocated to non-regulated operations[148].

Comparator Utilities Use Varied Cost Allocators to Allocate IT Costs

The KPMG Report asserts that NLH's use of average users is "generally aligned" with comparator utilities[149]. However, the comparator utility information provided by KPMG does not appear to support this assertion.

OPG and ENMAX appear to primarily use average users or similar measures to allocate IT costs. NB Power, Manitoba Hydro and BC Hydro use varied cost allocators that are more consistent with hybrid allocators using metrics such as O&M expense, assets, capital and labour activity charges to allocate IT costs. The KPMG Report indicates that BC Hydro uses a 50% capital/operating expenditures and 50% FTEs cost allocator to allocate IT costs.

The DGT Report did not address the issue of IT cost allocation as its scope was limited to the three methodology changes discussed in Sections 5.3 and 5.4 of this Evidence.

Assessment of an Alternative Cost Allocator for Allocation of IT Costs

It was noted in the preamble to requests for information that the three IT cost pools contained a diverse mix of costs related to individual IT users, overall enterprise systems and application development. In that context, NLH was requested to (i) explain if it had considered the use of a hybrid allocator to allocate the three IT cost pools, (ii) explain if use of a hybrid allocator would simplify the allocation of IT shared service costs by eliminating the need for the calculation of numerous metrics related to average users and (iii) provide an estimate of the change to the shared service cost allocation in the 2027 Test Year using a hybrid allocator to allocate the three IT cost pools[150].

In response, NLH indicated that it did not consider use of a hybrid allocator to allocate the three IT cost pools, as average users is a reasonable proxy for the consumption of IT services and this allocation approach was approved by the PUB in its 2013 GRA. NLH also indicated that while using the hybrid allocator may simplify the cost allocation framework, there were no material changes in the nature of the IT services or the underlying cost pools and as such, it continues to

[146] KPMG Report, Section 5.3.3.11, pg. 37
[147] CA-NLH-349
[148] KPMG Report, Section 5.4, Table 36, pg. 38
[149] KPMG Report, Section 5.3.2, Table 16, pg. 26
[150] CA-NLH-217 a b

view the use of average users as an appropriate cost driver and a better reflection of cost causation than a hybrid allocator.

In second round requests for information, NLH was requested to address the concern where automated, asset-driven or system-to-system activities consume IT resources independently of the number of users[151]. In response, NLH asserted that the primary purpose of IT services is to provide IT support to employees across the organization. NLH conceded that certain automated, asset-driven or system-to-system activities may consume IT resources independent of user counts, these activities are embedded within the overall enterprise IT environment and are not maintained or tracked separately by line of business.

NLH was requested in both rounds of requests for information to provide an illustrative estimate of the change to the shared service cost allocation in the 2027 Test Year using (i) a hybrid allocator (30% to regulated & 70% to non-regulated) to allocate the three IT cost pools and (ii) an estimate of the change to the allocation of shared service costs using the relative split of O&M costs (40% to regulated & 60% to non-regulated)[152]. NLH declined to provide such illustrative estimates in both rounds of requests for information.

Allocation of IT Shared Service Costs is an Outstanding Issue in this GRA

The issue of the appropriate cost allocator to allocate IT shared service costs is an outstanding issue in this regulatory proceeding. It has been 13 years since the 2013 GRA when the average user cost allocator was accepted by the PUB as a reasonable allocator for the three IT cost pools.

The average user cost allocator should have been re-evaluated by NLH based on significant changes in its business and operating environment, changes in how IT services are priced by vendors and changes in modern IT systems. The default assumption that every IT user places an equal burden on IT systems and as such reflects cost causation and consumption merits reconsideration. An approach focused solely on headcount (the proportions of average users and FTEs are similar) creates a labour intensity distortion between field operations and corporate operations and ignores capital and operating scale. The proportion of FTEs associated with regulated operations of 57% is consistent with the calculation of average users of IT of 57% for regulated operations[153].

In modern utilities, significant IT resources are consumed by automated, asset driven or system-to-system activities that operate independent of headcount or average users. Non-regulated lines of business, such as export marketing can consume significant IT resources and leverage the parent IT infrastructure. The assumption of consumption of IT services based on headcount/average users would understate the appropriate allocation to non-regulated operations.

[151] CA-NLH-349
[152] CA-NLH-217 c and CA-NLH-350
[153] KPMG Report, Section 5.3.3.1, Table 11, pg. 23

Many IT service providers/vendors no longer charge by the number of users/seats but rather they charge by data throughput and number of connected endpoints. Subscription based IT services are priced using several pricing metrics (hybrid pricing structures) in addition to number of users, including flat rates, usage-based/consumption-based and value-based/outcome-based. These modern, hybrid and usage-based/consumption-based pricing structures have changed since 2013 when per user/per seat was more prevalent.

The underlying types of costs that flow into the three IT cost pools are diverse and range between individual IT, operating technology (OT), application development and information systems management. The use of a single functional allocator (average users) is counterintuitive considering this diverse range of underlying costs and how modern IT systems function and are priced by vendors. Using a cost allocator that includes a weighting of the benefits of this diverse IT infrastructure on the basis of size, scale and scope of the operating units of NLH is appropriate and would balance considerations of scale and headcount.

The IT cost allocators are not standard across the utility comparators as demonstrated by the comparator utility information included in the KPMG Report. The proposed 57% allocation of IT shared service costs to NLH regulated operations is much higher than the allocation of governance costs (30%), capital costs (20%) and O&M costs (40%). There is no information on the record of this proceeding that rationalizes this much higher allocation of IT costs to NLH's regulated operations.

A Composite Allocator is Recommended to Allocate the NLH Three IT Cost Pools

It is recommended that the PUB approve an IT shared service cost allocator similar to BC Hydro, with 50% weight to FTEs and 50% weight to capital/operating expenditures, as being reasonable under the circumstances of the NLH 2026 GRA.

This approach would continue to provide a significant weight of 50% towards headcount (using FTEs instead of average users) in accordance with NLH's historic approach but also include 50% weight towards NLH's 2-part hybrid allocator that recognizes scale, scope and complexity. This approach is a stable middle ground that is consistent with the regulatory principle of cost causation. This recommendation would improve cost causation and also simplify the cost allocation process by eliminating the need to perform numerous calculations to derive average users across the three IT cost pools.

For illustrative purposes, this recommendation would result in the following allocation of the three IT cost pools between NLH regulated and non-regulated operations and the following impact to shared service allocations (in operating costs) and revenue requirements in the 2027 Test Year:

1. Allocation of **44%** of the three **IT cost pools** to NLH **regulated operations**. The 44% is calculated based on 50% weighting to FTEs and 50% weighting to the 2-part hybrid allocator: 44% = (57% * 0.5) + (30% * 0.5);

2. Allocation of **56%** of the three **IT cost pools** to NLH **non-regulated operations**. The 56% is calculated based on 50% weighting to FTEs and 50% weighting to the 2-part hybrid allocator: 56% = (43% * 0.5) + (70% * 0.5); and
3. **Shared service costs** allocated to NLH **regulated operations** (in operating costs) in the 2027 Test Year would **decrease by $2.6 million**. The $2.6 million reduction is calculated by taking the total IT cost pools of $19.8 million and multiplying by the change in the allocator between (i) the 44% recommended in this Evidence and (ii) 57% proposed by NLH: -$2.6 million = $19.8 million * -0.13 (0.44 – 0.57).

Additionally, given the rapid changes in technology and AI, review of the appropriate IT cost allocator should occur on a more regular basis at GRAs and at a minimum for the next NLH GRA.

6.0 There are Alternative Recommendations with Respect to NLH's Regulatory Deferral Account Proposals

This Section of the Evidence evaluates NLH's proposals with respect to regulatory deferral accounts (RDA) that impact the 2027 Test Year revenue requirements.

Recommendations to the PUB in this Section of the Evidence, are summarized as follows:

1. Approval of an amortization period of 10-years for the **Business Systems Transformation Program RDA**, considering the size of the deferral, the nature of the deferred costs are consistent with intangible assets and plans for continued service through on-going maintenance and upgrades. This recommendation will decrease 2027 Test Year amortization by $0.3 million. (NLH's proposal was an eight-year amortization period);
2. Approval of an amortization period of two-years for the **Phase Two Hearing Costs RDA**, considering the smaller size of the deferral and the long passage of time since this regulatory proceeding was concluded. This recommendation will increase 2027 Test Year amortization by $0.6 million. (NLH's proposal was an eight-year amortization period);
3. Approval of an amortization period of five-years for the **Reliability & Resource Adequacy Study Review RDA**, considering the recency of additions to the RRA Study RDA and the larger balance in the account ($5.1 million). This recommendation will increase the proposed 2027 Test Year amortization by $0.4 million. (NLH's proposal was an eight-year amortization period);
4. Approval of an amortization period of two-years for the **External GRA Hearing Costs RDA**, consistent with the recommendation that the PUB direct that the next NLH GRA be filed in 2028 (based on 2029 and 2030 Test Years). This recommendation will increase 2027 Test Year amortization by $0.4 million (NLH's proposal was a four-year amortization period);
5. Approval of NLH's proposals to amortize the balance in the **Muskrat Falls Sustaining Capital RDA** based on the composite depreciation rates of the Muskrat Falls Assets and include this RDA in rate base. It is also recommended that the PUB continue to scrutinize these sustaining capital expenditures in future GRAs given their unique regulatory treatment and variable nature;
6. Acceptance of NLH's position that the **Holyrood TGS Accelerated Depreciation RDA** recovery period will not be determined in the current GRA proceeding. It is also recommended that the recovery period be determined at a future GRA proceeding and not a one-off/separate regulatory application; and
7. Approval of financing costs for the **Long-Term Supply Cost Variance Deferral Account** at the short-term borrowing rate (and not WACC as proposed by NLH), considering the nature and expected operation of this RDA as a variance account handled through short-term bridge financing (working capital), NLH's capacity to finance this RDA through its short-term borrowing facilities and concerns with respect to the inconsistency of higher WACC financing costs and the Government's Rate Mitigation Plan.

6.1 This Section of the Evidence Evaluates & Makes Recommendations on NLH's Regulatory Deferral Account (RDA) Proposals that Impact the 2027 Test Year Revenue Requirements

This section of the Evidence evaluates and makes recommendations on NLH's regulatory deferral account (RDA) proposals that impact the 2027 Test Year revenue requirements, carrying costs proposals with respect to the Long-Term Supply Cost Variance deferral account and NLH's position with respect to the Holyrood TGS Accelerated Depreciation Deferral Account. The RDAs addressed in the following sub-sections below (in the order that they are presented in Chapter 5 of the GRA filing) are as follows:

1. Business Systems Transformation Program Deferral Account;
2. Phase Two Hearing Costs Deferral Account;
3. Reliability & Resource Adequacy Study Review Deferral Account;
4. Muskrat Falls PPA Sustaining Capital Deferral Account;
5. External GRA Hearing Costs Deferral Account;
6. Holyrood TGS Accelerated Depreciation Deferral Account; and
7. Long-Term Supply Cost Variance Deferral Account.

Please note that the Allowance for Funds Used During Construction Deferral Account is not addressed in this section of the Evidence as it was denied by the PUB in Order No. P.U. 30(2026).

This section of the Evidence does not address NLH RDA proposals that impact cost of service and rate design such as the (i) Frequency Converter Depreciation Deferral Account (ii) Electrification Cost Deferral Account (iii) Return on Equity Rate Change Deferral Account and (iv) Rural Labrador Interconnected - Revenue Deficiency Deferral Account.

6.2 It is Recommended that the Business Systems Transformation Program Deferral Account Be Amortized Over 10 Years which Would Reduce 2027 Test Year Amortization by $0.3 Million

NLH's 2027 Test Year revenue requirement proposals with respect to the Business Systems Transformation Program Deferral Account (BST RDA) are summarized as follows[154]:

1. **Proposed Amount to be Amortized**: $14.5 million;
2. **Proposed Amortization Period**: Eight (8) years commencing in 2027; and
3. **Proposed 2027 Test Year Amortization**: $1.8 million.

NLH indicates that $6.7 million associated with the Business Systems Transformation Program was approved for recovery in the BST RDA in PUB Order No. P.U. 27(2022) and that it has

[154] Chapter 5, Section 5.6.1, pg. 5.16

requested an additional $7.8 million of forecast costs be deferred to December 31, 2026 in an application that was approved by the PUB in Order No. P.U. 18(2026)[155].

In NLH's view, regulated utilities generally file GRAs every three to five years, with a typical frequency or cadence of four years (average of three to five years). NLH is proposing to amortize the $14.5 million balance in the BST RDA over eight years, which it asserts spans two regulatory cycles of four years each. It is noted as an aside, that as outlined in Section 3.8 of this Evidence, the typical interval between GRAs for crown-owned hydro utilities is every 2 to 3 years.

NLH indicates that the assets underlying the BST RDA were placed into service in 2018 and as such the remaining useful life of the original assets is approximately two years, based on the latest depreciation study. NLH notes that these assets will likely continue to provide service and value well beyond this remaining two-year period through on-going maintenance, upgrades and enhancement activities. In NLH's view, its proposal of an eight-year amortization period for the BST RDA is a reasonable balance between timely cost recovery, intergenerational equity and customer rate stability[156].

NLH also conceded that it is not established PUB regulatory practice to amortize regulatory deferral account balances over a specific number of regulatory cycles. As such, linking the amortization period of the BST RDA to two, four-year regulatory cycles is not recommended.

It is recommended that the PUB approve an amortization period of 10-years (consistent with the recent depreciation study/technical update[157]) for the BST RDA, considering the size of the deferral, the nature of the deferred costs are consistent with intangible assets and NLH's plans for continued service through on-going maintenance, upgrades and enhancement activities. The impact of this recommendation is to slightly decrease the proposed amortization in the 2027 Test Year by $0.3 million, from $1.8 million to $1.5 million ($14.5 million / 10 years).

6.3 It is Recommended that the Phase Two Hearing Costs Deferral Account Be Amortized Over Two Years which Would Increase 2027 Test Year Amortization by $0.6 Million

NLH's 2027 Test Year revenue requirement proposals with respect to the Phase Two Hearing Costs Deferral Account (Phase Two RDA) are summarized as follows[158]:

1. **Proposed Amount to be Amortized**: $1.7 million;
2. **Proposed Amortization Period**: Eight (8) years commencing in 2027; and
3. **Proposed 2027 Test Year Amortization**: $0.2 million.

[155] CA-NLH-203 a
[156] NP-NLH-080
[157] CA-NLH-269
[158] Chapter 5, Section 5.6.4, pgs. 5.18 to 5.19

NLH indicates that the PUB directed in Order No. P.U. 13(2026) that the Phase Two RDA be created to include professional services-consulting fees, salary transfers and overtime costs for 2014, 2015 and subsequent years relating to Phase Two of its investigation into the January 2014 outages and that this proceeding was concluded in 2019.

NLH asserts that its proposed eight-year amortization period (two, four-year regulatory cycles) is a balanced approach that moderates near-term rate impacts while ensuring timely recover of prudently incurred costs.

NLH indicated that it had considered a shorter amortization period for this RDA but was concerned with respect to moderating near-term rate impacts and that a four-year amortization for the Phase Two RDA would increase amortization in the 2027 Test Year from $0.2 million to $0.4 million[159]. There have been no additions to the Phase Two RDA since 2020[160].

Under NLH's recommendation the Phase Two RDA will not be fully recovered until 2034, approximately 15 years after the conclusion of the associated regulatory proceeding. This appears excessively long given the circumstances. In addition, customers will also be concurrently paying for the amortization of the Reliability & Resource Adequacy Study Review Deferral Account concurrently in rates (please see Section 6.4 below).

It is recommended that the PUB approve an amortization period of two-years for the Phase Two RDA, considering the smaller size of the deferral and the long passage of time since this regulatory proceeding was concluded (2019). Under this recommendation, the Phase Two RDA will be recovered by 2028, which is approximately 9 years after the conclusion of the associated regulatory proceeding and by the recommended timing of the next GRA for a 2029 Test Year. The impact of this recommendation is to increase the proposed amortization in the 2027 Test Year by $0.6 million, from $0.2 million to $0.8 million ($1.7 million / 2 years).

6.4 It is Recommended that the PUB Approve a Five Year Amortization Period for the Reliability & Resource Adequacy Study Review Deferral Account which Would Increase 2027 Test Year Amortization by $0.4 Million

NLH's 2027 Test Year revenue requirement proposals with respect to the Reliability & Resource Adequacy Study Review Deferral Account (RRA Study RDA) are summarized as follows[161]:

1. **Proposed Amount to be Amortized**: $5.1 million;
2. **Proposed Amortization Period**: Eight (8) years commencing in 2027; and
3. **Proposed 2027 Test Year Amortization**: $0.6 million.

[159] CA-NLH-204, CA-NLH-253 c and CA-NLH-331
[160] CA-NLH-193, Attachment 1, pg. 2
[161] Chapter 5, Section 5.6.5, pg. 5.19

NLH indicates that the PUB directed in Order No. P.U. 29(2019) and Order No. P.U. 8(2021) that the RRA Study RDA be created to include the PUB's external consulting costs and approved intervenor costs associated with the Reliability and Resource Adequacy Study Review and the external costs for professional services and contractors related to the assessment to determine the potential long-term viability of the Holyrood Thermal Generating Station (TGS).

NLH asserts that its proposed eight-year amortization period (two, four-year regulatory cycles) is a balanced approach that moderates near-term rate impacts while ensuring timely recovery of prudently incurred costs. NLH indicated that a four-year amortization for the RRA Study would increase amortization in the 2027 Test Year by $0.6 million from $0.6 million to $1.2 million[162].

There are on-going additions to the RRA Study RDA to the 2027 Test Year[163], but NLH is not forecasting any further additions from 2028 to 2030[164].

As was the case for the Phase Two RDA, amortization of these costs to 2034 appears to be an excessively long period of time. However, considering the recency of additions to the RRA Study RDA (and associated probability of more enduring value for ratepayers) and the more material balance in the account ($5.1 million) - it is recommended that the PUB approve a five-year amortization period for the RRA Study RDA. The impact of this recommendation is to increase the proposed amortization in the 2027 Test Year by $0.4 million, from $0.6 million to $1.0 million ($5.1 million / 5 years).

6.5 It is Recommended that the PUB Approve Amortization of the Muskrat Falls PPA Sustaining Capital Deferral Account Using Composite Depreciation Rates & Inclusion in Rate Base

NLH's 2027 Test Year revenue requirement proposals with respect to the Muskrat Falls PPA Sustaining Capital Deferral Account (MFSC RDA) are summarized as follows[165]:

1. **Proposed Amount to be Amortized**: $43.6 million with on-going additions for the life of the Muskrat Falls PPA;
2. **Proposed Amortization Period**: Composite depreciation rates for the Muskrat Falls Generating Facility (1.42%) and Labrador Transmission Assets (1.71%) - commencing in 2027; and
3. **Proposed 2027 Test Year Amortization**: $0.7 million.

NLH indicates that the PUB directed in Order No. P.U. 33(2021) that the MFSC RDA be created effective on the date that NLH was required to begin payments under the Muskrat Falls PPA. The Muskrat Falls PPA requires NLH to fund the sustaining capital costs of the Muskrat Falls Assets at

[162] CA-NLH-204, CA-NLH-253 c and CA-NLH-331
[163] CA-NLH-193, Attachment 1, pgs. 1 to 9 and Schedule D-V, pg. 1
[164] CA-NLH-192, Attachment 1, pg. 1
[165] Chapter 5, Section 5.6.6, pgs. 5.19 to 5.20

the time the expenditures are incurred. The purpose of the MFSC RDA is to match the period of cost recovery through rates with the period over which the assets are providing service to ratepayers (consistent with the regulatory principle of intergenerational equity) and prevent material rate volatility associated with expensing these costs in the year incurred for rate-setting purposes[166].

NLH is proposing that the MFSC RDA be amortized based on the composite rates for the Muskrat Falls Generating Facility (1.42% = equivalent to 70.6 years) and Labrador Transmission Assets (1.71% = equivalent to 58.6 years), as recommended by Concentric[167].

The sustaining capital expenditures (additions to the MFSC RDA) have ranged from $0.5 million in 2022 to $19.9 million forecast in 2026, with forecast expenditures in the 2027 Test Year of $9.0 million. The most material sustaining capital expenditures (over $1 million) are the installation of shunt reactors ($25.2 million), installation of a downstream public safety boom ($4.4 million) and 315 kV right-of-way vegetation clearing and access trail improvements ($2.2 million)[168]. NLH is forecasting sustaining capital expenditures additions of between $3 million and $5 million on an annual basis into the MFSC RDA between 2028 and 2030[169].

NLH indicated that the sustaining capital payments do not include any amount for interest during construction (IDC) or allowance for funds used during construction (AFUDC) or any other financing charge as the financing of these projects is from NLH regulated operations[170]. NLH is proposing that the MFSC RDA be included in rate base as this treatment appropriately recognizes the on-going investment represented by the unrecovered balance and is consistent with the long-term recovery of capital cost over the period in which customers receive the related benefits[171].

It is recommended that the PUB approve NLH's proposals to amortize the balance in the MFSC RDA based on the composite depreciation rates of the Muskrat Falls Assets and inclusion in rate base. The net impact of NLH's proposals is that the Muskrat Falls sustaining capital expenditures are treated like capital assets and amortized over their expected useful lives for rate-setting purposes.

It is also recommended that the PUB continue to scrutinize these sustaining capital expenditures in future GRAs given their unique treatment, variable nature and that this RDA is expected to grow over time as sustaining capital expenditures are made.

[166] Chapter 4, Section 4.3.2, pgs. 4.9 and 4.10
[167] Exhibit 9 and CA-NLH-199, Attachment 2 and Attachment 3
[168] CA-NLH-200, Attachment 1 and Attachment 2 and CA-NLH-329 a b c
[169] CA-NLH-192, Attachment 1, pg. 1
[170] CA-NLH-330 a
[171] PUB-NLH-144 c

6.6 It is Recommended that the PUB Approve a Two Year Amortization Period for the External GRA Hearing Costs Deferral Account which Would Increase 2027 Test Year Amortization by $0.4 Million

NLH's 2027 Test Year revenue requirement proposals with respect to the External GRA Hearing Costs Deferral Account (GRA Costs RDA) are summarized as follows[172]:

1. **Proposed Amount to be Amortized**: $1.5 million;
2. **Proposed Amortization Period**: Four (4) years commencing in 2027; and
3. **Proposed 2027 Test Year Amortization**: $0.4 million.

NLH indicates that it is forecast to incur approximately $1.5 million of external regulatory costs associated with the 2026 GRA regulatory process. NLH outlined that it was directed by the PUB to pay $1.8 million of PUB and intervenor costs flowing from the 2017 GRA – and that it had estimated the $1.5 million for the 2026 GRA considering the complexity of the 2026 GRA, escalation in costs since that time and that the longer procedural history of the 2017 GRA (the final compliance Order being issued approximately two years after the filing of the application)[173].

NLH's recommended four-year amortization period is based on its view of a typical GRA frequency/cadence of four years and its position that its next GRA should be filed no earlier than 2030 (2031 Test Year).

Consistent with the recommendation in Section 3.8 of this Evidence, that the PUB direct NLH to file its next GRA in 2028 (based on 2029 and 2030 Test Years), it is recommended that the PUB approve an amortization period of two-years for the GRA Costs RDA, being the period of benefit from this regulatory proceeding. The impact of this recommendation is to increase the proposed amortization in the 2027 Test Year by $0.4 million, from $0.4 million to $0.8 million ($1.5 million / 2 years).

6.7 It is Recommended that the Recovery Period of the Holyrood TGS Accelerated Depreciation Deferral Account be Set at a Future GRA When Information on the Retirement Date is Available

NLH is not proposing the disposition of the balance in the Holyrood TGS Accelerated Depreciation Deferral Account (Holyrood TGS RDA) at this time[174]. NLH is proposing that the balance in the Holyrood TGS RDA be included in rate base[175].

[172] Chapter 5, Section 5.6.9, pgs. 5.21
[173] CA-NLH-205 and CA-NLH-332
[174] Chapter 5, Section 5.6.10, pg. 5.21
[175] PUB-NLH-143 c

NLH indicates that in Order No. P.U. 33(2021), the PUB approved the creation of the Holyrood TGS RDA to defer the differences in excess of $2.5 million (referred to as the "deadband") between the test year depreciation expense and the actual accelerated depreciation for the Holyrood TGS assets in 2022 and 2023. Further, in Order No. P.U. 1(2024), the PUB approved NLH's application to continue to defer these differences until the assumed end-of-steam generation and directed that a report on this activity and operation of this RDA be provided at the next GRA.

PUB Directed Report on the Activity and Operation of the Holyrood TGS RDA Since the Last GRA

NLH filed the directed report in the 2026 GRA filing[176], which indicates the following with respect to the Holyrood TGS RDA:

1. The end-of-steam generation date is to 2030 or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met;
2. The cumulative balance owing to customers at the end of the 2027 Test Year is $11.4 million;
3. The cumulative balance is expected to shift to a balance owing to NLH by 2028 of $0.3 million – with a forecast balance owing to NLH of $27.9 million by 2030;
4. This shift is primarily driven by capital projects completed in the later years of the Holyrood TGS such that capital projects forecast to be placed in service at the end of 2027 are assumed to be depreciated over approximately two years; and
5. NLH has assumed an end-of-steam generation date of March 31, 2030 for forecasting purposes, this date is an assumption only – and the actual retirement date of the Holyrood TGS will be dependent on the timing and in-service status of replacement generation.

The following table summarizes the projected balances in the Holyrood TGS RDA from the 2027 Test Year to the 2030 Forecast:

[176] Exhibit 11, pgs. 1 to 3

Table 10

Holyrood TGS Accelerated Depreciation Deferral Account - 2027 Test Year to 2030 Forecast ($ Millions)				
	1	**2**	**3**	**4**
	2027	**2028**	**2029**	**2030**
	Test Year	**Forecast**	**Forecast**	**Forecast**
Actual Depreciation (A)	29	43	55	14
Test Year Depreciation (B)	29	29	29	8
Variance - Owing to NLH (Owing from NLH) (C=A-B)	**-**	**14**	**26**	**6**
Deferral Amount (Net) - Owing to NLH (Owing from NLH) (D)	**-**	**11**	**24**	**4**
Opening Balance - Owing to NLH (Owing from NLH) (E)	(11)	(11)	-	24
Deferral Amount (F)	-	11	24	4
Closing Balance - Owing to NLH (Owing from NLH) (G=E+F)	**(11)**	**-**	**24**	**28**

The key observations with respect to Table 10, are as follows:

1. The **opening balance** in the Holyrood TGS RDA in the 2027 Test Year is $11 million owing to customers;
2. Actual depreciation (accelerated) and test year depreciation is $29 million, which is the same amount as is forecast in the 2027 Test Year, resulting in **no variance** or **deferral amount** for 2027;
3. The **increase** in **accelerated depreciation** in the 2028 forecast to the 2030 forecast results in variances owing to NLH and deferrals (net of a $2.5 million deadband) of $11 million, $24 million and $4 million, respectively;
4. The **forecast balance** in the Holyrood TGS RDA in 2030 is $28 million owing to NLH; and
5. Amounts in **2030 forecast** are **prorated** for a part of a year to March 31, 2030, based on the planning assumption inherent in the NLH financial forecast.

NLH indicates that the appropriateness, timing, structure of any recovery proposal will be influenced by several factors that remain uncertain at this time, including: (i) the actual retirement date of the Holyrood TGS, (ii) final magnitude of the RDA balance and (iii) if the final RDA balance is owing to NLH or owing to customers. Given the uncertainty, NLH has not proposed the disposition of the Holyrood TGS RDA as part of the 2026 GRA.

NLH submits that it would be premature to advance a recovery proposal absent clarity on these uncertain matters and that it will address the disposition of the RDA in a future regulatory application.

In the request for information process, NLH confirmed that the current "planning assumption" of the retirement date for the Holyrood TGS remains unchanged at this time – and that it will reassess the situation in its next Reliability and Resource Adequacy Update, planned for 2027[177].

NLH indicated that sustaining capital expenditures related to the Holyrood TGS are forecast at $33.3 million in 2027 and $18.6 million in 2028[178]. NLH also noted that any extension of the Holyrood TGS beyond the assumed retirement date of March 31, 2030, would require it to reassess both the necessary sustaining capital requirements beyond 2028 and associated capital recovery[179].

Holyrood TGS RDA Accelerated Depreciation Scenario

During the request for information process, a scenario was requested of the level of accelerated depreciation that would have to be included in the 2027 Test Year (rates) that would result in the cumulative balance in the Holyrood TGS RDA being forecast at zero by March 31, 2030[180]. The following table summarizes this accelerated depreciation scenario:

Table 11

Holyrood TGS Accelerated Depreciation Scenario - 2027 Test Year to 2030 Forecast ($ Millions)				
	1	**2**	**3**	**4**
	2027	**2028**	**2029**	**2030**
	Test Year	**Forecast**	**Forecast**	**Forecast**
Actual Depreciation (A)	29	43	55	14
Test Year Depreciation (B)	39	39	39	10
Variance - Owing to NLH (Owing from NLH) (C=A-B)	**(10)**	**4**	**16**	**4**
Deferral Amount (Net) - Owing to NLH (Owing from NLH) (D)	**(7)**	**2**	**14**	**2**
Opening Balance - Owing to NLH (Owing from NLH) (E)	(11)	(18)	(16)	(2)
Deferral Amount (F)	(7)	2	14	2
Closing Balance - Owing to NLH (Owing from NLH) (G=E+F)	**(18)**	**(16)**	**(2)**	**-**

[177] PUB-NLH-082
[178] PUB-NLH-097 a
[179] NP-NLH-161
[180] NP-NLH-162

Table 11 demonstrates that the Holyrood TGS accelerated depreciation would have to be set at $39 million in the 2027 Test Year in order to reduce the forecast balance in the related RDA to zero by March 31, 2030, consistent with NLH's planning assumption for the Holyrood TGS on March 31, 2030. This would represent a $10 million increase in depreciation in the 2027 Test Year over the $29 million that is proposed by NLH – and a total increase of $22 million ($12 million + $10 million) over the amount that is currently included in approved revenue requirements of $17 million (please see Table 6 of Section 4.4 of this Evidence).

Recommendations on the Holyrood TGS RDA

Given the foregoing, it is recommended that the PUB accept the NLH position that the Holyrood TGS RDA recovery period not be determined in the 2026 GRA proceeding. The record of the proceeding suggests too much uncertainty with respect to the timing of the retirement of the Holyrood TGS to determine a recovery period of the accelerated depreciation for rate-setting purposes.

It would be premature to set a recovery period given the significant uncertainty and to increase 2027 Test Year revenue requirements related to the Holyrood TGS accelerated depreciation to $39 million to meet an artificial "planning assumption" for forecasting purposes - that has yet to be validated in the real world. In the interim it is appropriate that the Holyrood TGS RDA be included in rate base given the underlying nature with respect to the assets that it relates to.

It is also recommended that the recovery period of the Holyrood TGS RDA be determined in the context of a GRA proceeding and not a one-off/separate regulatory application. The recovery period of the Holyrood TGS RDA should be set in the context of the overall revenue requirements and revenue deficiencies that can only be understood during a GRA proceeding - and by considering generally accepted regulatory principles of rate stability and intergenerational equity.

6.8 It is Recommended that the PUB Approve Financing Costs at the Short-Term Borrowing Rate for the Long-Term Supply Cost Variance Deferral Account

NLH is proposing the creation of a new Long-Term Supply Cost Variance Deferral Account (LTSCVDA) effective January 1, 2027, with interest (also referred to as financing costs or carrying costs) calculated based on the WACC in its latest approved test year. NLH is proposing that the approach for disposition or recovery of the LTSCVDA and any balances remaining in the existing SCVDA (after the transition to the LTSCVDA) is to be addressed in future applications following this GRA proceeding[181].

NLH notes that its existing Supply Cost Variance Deferral Account (SCVDA) was approved by the PUB effective November 21, 2021 in PUB Order No. P.U. 33(2021) and Order No. P.U. 4(2022)

[181] Chapter 5, Section 5.7.1, pgs. 5.22 to 5.23 and NLH Letter of Application, Regulatory Accounting, Item (vi), pg. 9

and enables deferral of costs related to its requirement to commence payment of Muskrat Falls Project costs. In addition to Muskrat Falls Project Costs and Rate Mitigation Funding, the SCVDA also includes variances for costs and revenues from NLH's approved test year for items such as (i) fuel costs associated with Holyrood TGS (ii) transmission tariff revenue (iii) net revenues from exports (iv) greenhouse gas credit revenues (v) load variations (vi) rural rate adjustments and (vii) other Island Interconnected System supply cost variances.

In the application associated with the creation of the SCVDA, NLH indicated that it would provide evidence on a long-term approach to the SCVDA in its next GRA, including proposed allocation and recovery approaches. However, in the current GRA filing NLH has changed its position and now plans to propose the disposition of any balances remaining in the existing SCVDA after the transition to the LTSCVDA in an application following the current GRA proceeding.

In Order No. P.U. 33(2021), the PUB ordered that the calculation of finance costs on the SCVDA be calculated based on NLH's short-term borrowing costs, noting NLH's plan to use short-term borrowing in the near-term to finance this RDA[182]. Since the implementation of the SCVDA, NLH has implemented a Project Cost Recovery Rider and rate mitigation funding has been applied or is committed to reduce the balance in the account to zero.

NLH's proposal is for the LTSCVDA to come into effect on January 1, 2027, with NLH noting that the variances and resulting balances in this new RDA are expected to be much lower in comparison to the existing SCVDA, as project costs and rate mitigation funding will be included in its cost of service and test year revenues, prior to this account becoming effective. Given this difference between the LTSCVDA and SCVDA, NLH is proposing that the financing costs on the LTSCVDA be based on its WACC as approved in its test year.

NLH's plan is to address the approach for the disposition of the LTSCVDA in a future application to the PUB.

Summary of Request for Information Process with respect to the LTSCVDA

A summary of information on the LTSCVDA from the request for information process is as follows:

1. **Separate Consideration of Financing Costs and Disposition Methodology**: NLH is of the view that it is appropriate to address the disposition of the LT SCVDA at a future regulatory proceeding and the appropriate financing cost rate for rate-setting purposes at the current GRA proceeding as these issues serve two purposes. NLH asserts that it and its customers should have regulatory certainty regarding the treatment of financing costs from the inception of the account and that the determination of the methodology for disposition of this RDA can occur at a later date[183] and is not required for the establishment and operation of the LT SCVDA at this point in time[184];

[182] Chapter 5, Section 5.7.6, pgs. 5.26 to 5.28
[183] CA-NLH-322
[184] CA-NLH-325 b c

2. **Expected Operation of this RDA**: NLH indicates that in practice, the balance in the LTSCVDA would be expected to accumulate gradually throughout the year rather than remain outstanding at a certain level throughout the year[185], any net balance in the LTSCVDA owing from customers is funded/extinguished annually through the rate mitigation plan up to and including 2030[186] and the LTSCVDA captures "variances" between test year and actual costs and revenues[187];
3. **Additional Reasons for Proposal for Financing Costs at WACC**: In addition to the expectation of lower balances in the LTSCVDA (than the existing SCVDA) - NLH asserts that RDA balances are financed with a combination of debt and equity funds that are not traceable to a single source and that the treatment of the LTSCVDA should not deviate from current regulatory practice in Newfoundland and Labrador[188]; and
4. **Impact of Financing Costs at WACC as Compared to Short-Term Debt Rate:** NLH asserts that forecasting the balances in the LTSCVDA through to 2030 would not provide meaningful information[189]. NLH provided an illustrative calculation of the financial differential between WACC (4.88%) and a short-term debt rate (3.39%), assuming a $100 million balance in the LTSCVDA outstanding for a full 12-month period. This illustrative calculation indicated higher financing costs of $1.5 million per year using the WACC as proposed by NLH. NLH also noted that the $1.5 million higher financing costs should be viewed as the "upper end" of the potential annual impact for this example, as it assumes a constant $100 million balance outstanding for the full 12-month period. NLH noted that a $100 million balance outstanding for an average of six months would result in $0.8 million of higher financing costs using WACC[190].

It is also noted that NLH maintains a Promissory Note Program of up to $300 million and a Committed Credit Facility of up to $600 million[191] (total of $900 million) and these short-term debt facilities are used to fund working-capital requirements[192].

Analysis & Recommendations on the Creation & Disposition of the LTSCVDA

In terms of the creation of the LTSCVDA, it appears that there was an intent to create this account from the timing that the existing SCVDA was approved. It is not entirely clear why there has to be a new SCVDA account created effective January 1, 2027, but it is not unreasonable that such

[185] CA-NLH-191 c
[186] CA-NLH-196
[187] CA-NLH-328
[188] PUB-NLH-093 a b and CA-NLH-325 a
[189] CA-NLH-196
[190] PUB-NLH-142 e
[191] CA-NLH-273
[192] CA-NLH-274

an RDA continue on after January 1, 2027 in order to keep NLH and ratepayers whole with respect to the numerous costs and revenues that are captured in the LTSCVDA.

While the LTSCVDA may satisfy the revenue-related attributes (revenue sufficiency and rate stability) and cost-related attributes (if properly allocated to customer classes) of ratemaking, its complexity is such that it is not as well suited to the practical-related attributes of ratemaking (understandability and administrative simplicity). The complexity of the LTSCVDA may make resolution of the recovery/disposition methodology related to this account more difficult to understand and resolve.

The lack of a proposal from NLH related to the recovery/disposition methodology of the LTSCVDA in this GRA is problematic. The recovery of the LTSCVDA is low risk for NLH and it is more interested in regulatory certainty on the financing costs to be charged to this RDA. For ratepayers, the lack of understanding of the recovery/disposition methodology is another source of uncertainty for future rates and rate-setting processes.

The practical reality of the situation for the PUB and intervenors to this GRA proceeding is that (i) the absence of a well thought out proposed recovery/disposition methodology from NLH, and (ii) the inability of that proposal to be tested through the request for information process and addressed in intervenor evidence - is such that by default NLH's proposal to address the disposition in a future application must be reluctantly accepted.

It is unclear from the record of this proceeding, what further event/milestone is expected by NLH or what further information is required by NLH, in order to develop a sound recovery/disposition methodology for the LTSCVDA.

Analysis & Recommendations on Financing Costs for the LTSCVDA

It is recommended that the PUB approve financing costs on the proposed LTSCVDA at NLH's short-term borrowing rate (and not the WACC as proposed by NLH) for the reasons noted below.

The reasoning that NLH provided in its application to move from the approved short-term borrowing rate of the existing SCVDA to a WACC for the LTSCVDA - was that the LTSCVDA is expected to have much lower balances than the existing SCVDA. This reasoning may be a difference, but it is not a change in circumstances that logically would support use of the WACC for financing costs. A lower expected balance would appear to support a short-term borrowing rate for the LTSCVDA.

The nature of the LTSCVDA is that of a variance account which is expected by NLH to be extinguished within the next year. As such, it is a short-term working capital issue that requires bridge financing and does not require long-term equity financing. NLH has up to $900 million of short-term financing capacity available through its short-term borrowing program and credit facility to finance the balances in the LTSCVDA.

This type of a short-term variance RDA is a pass-through account and represents low risk of recovery by NLH. It is not reasonable that NLH earn an equity risk premium on this RDA, which it would if a WACC was approved by the PUB. This is a different situation from long-term capital investments upon which utilities are allowed to earn a return on equity (ROE).

As noted in Section 6.1 of this Evidence, the PUB has recently issued its decision which denied NLH's application to create an AFUDC RDA. In that decision, the PUB found that (i) there was no basis to change its previous determination that NLH be treated as a crown-owned utility (and not an investor-owned utility) and (ii) the adoption of AFUDC would increase costs to be funded by customers or through rate mitigation and as such it was uncertain whether approving the use of AFUDC would be consistent with the Government's Rate Mitigation Plan.

The PUB does not exercise regulatory control over the sources and timing of rate mitigation funding. Care should be taken not to create a perverse incentive on NLH's part to maintain higher balances in the LTSCVDA in order to earn a ROE that must be paid for by ratepayers.

The NLH proposal to charge financing costs on the LTSCVDA at WACC is a similar situation to the request for AFUDC, as WACC and AFUDC both include an equity risk premium and would increase the costs to be funded by customers through rates or by NLH through additional rate mitigation funding. The consistency of the use of WACC for the LTSCVDA and the Government's Rate Mitigation Plan is similarly uncertain as was the case in NLH's application for an AFUDC RDA.

Darren Rainkie, CPA, CA, CBV

Principal – Darren Rainkie Consulting
Phone: 204.782.5877 or Email: darrenrainkie@gmail.com

HANDS ON & MULTI-FACETED EXPERTISE

IMPROVED REGULATORY & BUSINESS OUTCOMES FOR CLIENTS

QUALIFICATIONS & EXPERTISE

- Executive Utility Leadership
- Regulatory Policy & Strategy
- Revenue Requirement Specialist
- Regulation Process Management
- Financial Management
- Adept Expert Witness

CAREER HIGHLIGHTS

- Deep and multi-faceted expertise in all aspects of rate-regulation (1990-Present)
- Extensive experience testifying as a policy & subject matter expert at regulatory proceedings (2000-Present)
- Executive experience (Acting CEO, CFO, Controller & Treasurer) at Manitoba Hydro & Centra Gas (2006-2017)
- Senior level expertise in a broad range of financial management disciplines (2000-2017)

PROFESSIONAL EXPERIENCE

- Independent Consultant 2017-Present
- Manitoba Hydro 1999-2017
- Centra Gas 1994-1999
- Price Waterhouse 1988-1994

EDUCATION

- Chartered Business Valuator 1993
- Chartered Professional Accountant (Chartered Accountant) 1991
- B. Com. (Hons. – With Distinction), University of Manitoba 1988

PROFILE

Darren leverages his 36 years of **hands on experience** and **multi-faceted expertise** in rate-regulation, utility & financial management to **improve regulatory & business outcomes for clients** that participate in and are impacted by rate-regulation - including applicants, intervenors, utility customers, regulatory tribunals & government agencies. He specializes in providing rate-regulation and financial advisory services, with an emphasis on regulatory policy & strategy and revenue requirement & fiscal matters.

The **client benefits** from **Darren's advisory services** are summarized as follows:

Access to a Comprehensive Suite of High-Quality Regulatory Services – Darren's deep specialization in rate-regulation and multi-faceted regulatory expertise enables him to provide high-quality advice to clients on regulatory policy, strategy, issues and process – that is customized/adapted to the relevant sector, ownership structure, rate-setting framework, subject matter and type of regulatory proceeding.

Effective Diagnosis of Issues & Sound, Practical Advice – Decades of hands on and executive level public utility experience - gives Darren the ability to effectively identify critical issues, evaluate alternative options & risks and develop pragmatic solutions for clients that are aligned with longer-term vision and strategic direction and balance utility and customer interests.

Integrated, Broad-Based & Credible Recommendations – Darren's financial management expertise results in recommendations to clients that evaluate the broader financial implications & integrates these implications into the ratemaking framework – with the inherent credibility associated with first-hand & senior level experience applying this financial expertise in a complex regulated enterprise.

Sustainable Solutions & Greater Potential of Stakeholder Acceptance – Clients benefit from Darren's leadership experience, collaborative approach and ability to effectively engage with stakeholders – which leads to more sustainable solutions, greater potential of stakeholder acceptance, as well as opportunities to facilitate client knowledge transfer and learning.

Building Consensus & Commitment to Implement Recommendations – Darren's uses his excellent communication & influencing skills, along with his extensive experience providing testimony at regulatory proceedings – to assist clients in obtaining a shared understanding of issues & options with internal and external stakeholders and building consensus for and commitment to implementing recommendations.

OVERVIEW OF PUBLIC UTILITY REGULATORY EXPERIENCE

Deep Specialization in Rate Regulation & Multi-faceted Regulatory Expertise

- A deep specialization in rate-regulation encompassing the majority of a professional career spanning 36 years, including employment with/advising **multiple parties** to the regulatory process: providing advisory services to provincial regulators, executive oversight and management of rate applications and regulatory filings of applicant utilities and providing independent expert advice to intervenors and applicants.
- Multi-faceted regulatory expertise including **multiple sectors** (electricity, natural gas, mandatory auto insurance, water & waste, energy efficiency, district energy, propane, group 2 pipeline), a number of **jurisdictions** (British Columbia, Alberta, North West Territories, Manitoba, New Brunswick, Nova Scotia), various **ownership structures** (crown-owned, investor-owned and municipally-owned utilities) and a number of **rate-setting/legislative frameworks** (rate base/rate of return, modified cost of service, historic & future test years, multi-year rate applications).
- Extensive experience in a broad range of **regulatory proceedings** (general rate applications, revenue requirement applications, major capital project and certificate of public convenience and necessity reviews, integrated resource plan reviews, energy transition/decarbonization and demand-side management reviews, rate setting framework/multi-year rate plan reviews, thermal energy system regulatory framework reviews, cost of service methodology reviews, leading budgeting practices for regulated entities, back-up/top-up service pricing & terms, commodity cost prudence reviews/pass throughs, investment policy reviews, franchise expansion & feasibility test reviews, natural gas broker service improvements, debt & equity issues, accounting policy selection, depreciation rates, intercompany cost allocations & affiliate transactions, pipeline safety, integrity & construction methods, customer disconnections, automated meter reading and natural gas cooperative acquisitions) and expertise in all aspects of **rate-regulation subject matter** (regulatory policy, revenue requirements, cost of capital/capital structure, cost allocation and rate design).
- Experience with different types of **regulatory processes** (oral hearing, paper hearing, ex-parte, complaint based and alternative dispute resolution) and through all **regulatory cycle components** (strategy development & case planning, application & evidence preparation/evaluation, stakeholder engagement, witness training & preparation, discovery & hearing process management, presentation of expert testimony, cross examination & argument strategy/content, regulatory decision drafting, compliance filing preparation/evaluation, regulatory process improvement recommendations).

Hands On & Executive Level Public Utility Experience

- Hands on **public utility experience** through **23 years of employment** with a privately-owned natural gas utility and one of Canada's largest publicly owned, vertically integrated electric and natural gas utilities.
- Over 11 years of **executive leadership experience** actively collaborating in the management of the corporation, developing corporate & business unit strategic plans, developing risk management plans and successfully managing multiple strategic initiatives simultaneously.
- A **comprehensive understanding** of the **business, operations** and **risks** related to **regulated public utilities**, how decisions are made in this environment - as well as the strategic challenges facing regulated entities.
- A proven track record of developing **innovative financial** and **regulatory strategies** that are aligned with the overall vision and strategic direction of the organization - to ensure the on-going financial sustainability of the utility and respond to future business requirements.

Broad Range of First-Hand Financial Management Expertise – Applied to a Complex Regulated Enterprise

- Over 17 years of senior level and first-hand expertise in a **broad range** of **financial management disciplines** including: setting financial targets/key performance indicators, long-term financial forecasting, operating cost budgeting, capital cost budgeting, treasury & debt management, corporate risk management, accounting policy selection, financial & management reporting and internal cost allocation between lines of business.
- A **comprehensive understanding of utility financial models** and the elements that impact the model and financial performance, including key inputs, underlying processes, best practices, expected outcomes, options and key performance indicators. Demonstrated experience in applying this diverse financial management expertise and integrating them into the ratemaking framework of a complex regulated enterprise.
- Initiated, championed and actively participated in a number of transformational initiatives to ensure the ongoing financial sustainability of Manitoba Hydro during a period of extensive major capital investment, including: a comprehensive **review of corporate financial targets**, a complex **scenario analysis** to review the adequacy of financial reserves/forecast long-term rate impacts, a **multi-year budgeting strategy** designed to achieve operating cost savings; a **corporate asset management framework** to improve the prioritization of sustaining capital expenditures, an **alternate debt management strategy** to retire debt and improve the financial outlook and a top-down strategy driven approach and **transformation of rate applications** to balance financial integrity with interests of ratepayers.
- Demonstrated ability to **effectively identify issues impacting** the **long-term financial outlook** of **regulated enterprises**, evaluate historic and expected performance against key performance indicators, develop options & identify levers that can be used to positively impact rates to customers and make credible recommendations to intervenors, applicants and regulatory tribunals.

Collaborative Approach & Stakeholder Engagement Experience

- A principled and **collaborative leader** with extensive experience leading, developing, mentoring, collaborating and providing direction to a diverse team of senior professionals as well as cross-disciplinary project teams.
- **Worked collaboratively** with **internal officials** – such as subject matter experts, senior management, executive team, board committees and board of directors to achieve the **strategic, operational** and **financial goals.**
- Managed the interactions with and **build strong relationships** with **external stakeholders**, including provincial government officials, indigenous business partners, external auditors, investment banking institutions and credit rating agencies. As a result of the direct involvement with external stakeholders, have experience explaining the perspectives and issues of these stakeholders to regulatory stakeholders as an executive policy witness.
- Demonstrated capability to **engage with** and **build strong relationships** with **regulatory stakeholders**, including regulatory tribunal staff & advisors, consumer group/intervenor representatives & experts and applicant officials. Provided oversight and actively participated in a number of **regulatory stakeholder engagement sessions** with the objectives of fostering positive relationships, building shared understanding of participants and reducing the number of issues to be reviewed/contested during regulatory proceedings.

Adept Witness & Excellent Communication and Influencing Skills

- As a utility executive, oversaw and participated in the development and delivery of **numerous persuasive presentations** and **recommendations** to obtained direction/approvals from the executive committee, audit committee, board of directors and regulatory tribunals - with respect to financial targets, long-term financial forecasts, proposed rate increases, operating and capital expenditure plans, financing and risk management plans, depreciation study changes, accounting policy selection/IFRS implementation and financial reporting. As an advisor to a regulatory tribunal, intervenors and applicants, have delivered numerous briefings to the client on the significant issues arising in regulatory applications.
- An excellent **reputation** for the **ability to draft well constructed documents** and **reports**, and to organize complex business & regulatory concepts into compelling evidence, using clear and understandable language. The range of experience includes five years drafting regulatory decisions for a regulatory tribunal, 23 years drafting regulatory applications/reports for applicants and four years developing independent reports for intervenors and applicants.
- Over 20 years of **experience testifying** as a **subject matter witness**, **executive policy witness** and **independent expert** at regulatory proceedings. Areas of testimony include: policy & strategy (electric & natural gas general rate applications, major capital projects review, cost of gas prudence review, cost of service methodology review), financial targets, long-term financial forecasts, operating & capital cost forecasts, debt management strategies, depreciation studies, adoption of IFRS accounting policies for rate setting purposes, financial results, general revenue requirement components, rate base, return on equity, capital structure, financial feasibility tests, as well as regulatory approvals and procedural matters.

PROFESSIONAL EXPERIENCE

PRINCIPAL, DARREN RAINKIE CONSULTING **2017 – Present**

- Provide **rate-regulation advisory services** in the subject matter areas of policy, strategy, revenue requirements, cost of capital/capital structure, cost allocation, rate design, major capital project reviews, planning and management of regulatory applications and associated hearing processes, stakeholder engagement and witness testimony in regulatory proceedings.
- Provide **financial advisory services** in the subject matter areas of financial targets, long-term forecasting, operating & capital cost budgeting, debt management, risk management, intercompany cost allocation, financial reporting and business valuation.
- Provided independent expert evidence and testimony on the overall financial health of Manitoba Hydro, rate impacts and potential mitigating actions to reduce the rate impacts of the proposed major new facilities on behalf of the **Consumers Coalition** in the **Manitoba Hydro 2026 Major New Facilities Review** proceeding before the **Manitoba Public Utilities Board.**
- Provided independent advice to the **Office of the Consumer Advocate** with respect to **Newfoundland and Labrador Hydro's Application** for the **Approval of a Deferral Account for an Allowance for Funds Used During Construction** before the **Board of Commissioners of Public Utilities of Newfoundland and Labrador**.
- Provided independent expert evidence and testimony on regulatory policy and revenue requirement matters including integrated strategic management framework, financial position/outlook, financial targets, operating expenses, sustaining capital expenditures, debt management strategies, regulatory deferral accounts and indicative rate path on behalf of the **Consumers Coalition** in the **Manitoba Hydro 2025/26 to 2027/28 General Rate Application** proceeding before the **Manitoba Public Utilities Board.**

- Provided independent advice to the **Consumers Coalition** with respect to the **Manitoba Hydro Financial Target Review and Enterprise Benchmarking** consultation with interest parties in response to directives from the **Manitoba Public Utilities Board**.
- Provided independent expert evidence and testimony on regulatory policy and revenue requirement matters including operating expenses, integrated cost allocation methodology, debt management strategy, financial position/outlook and indicative rate path on behalf of the **Consumers Association of Canada (Manitoba)** in the **Centra Gas Manitoba Inc. 2024/25 General Rate Application** proceeding before the **Manitoba Public Utilities Board.**
- Provided independent expert evidence and testimony on regulatory policy and revenue requirement matters including risk assessment, financial targets, operating expenses, sustaining capital expenditures, debt management strategies and regulatory deferral accounts on behalf of the **Consumers Coalition** in the **Manitoba Hydro 2023/25 & 2024/25 General Rate Application** proceeding before the **Manitoba Public Utilities Board**, as well as the associated **Review & Vary Application** related to depreciation matters**.**
- Provided independent advice to the **Consumers Association of Canada (Manitoba)** on case strategy, corporate strategy/strategic plan and leading budgeting practices for regulated enterprises in connection with the **Manitoba Public Insurance 2025, 2026 and 2027 General Rate Applications** before the **Manitoba Public Utilities Board.**
- Provided independent advice to the **Consumers Association of Canada (Manitoba)** on case strategy in connection with the **Manitoba Public Insurance 2024 General Rate Application** before the **Manitoba Public Utilities Board.**
- Provided independent expert evidence on residential and streetlighting distribution investment policies related to four **Alberta distribution utilities (ATCO, ENMAX, EPCOR and Fortis)** on behalf of **BILD Alberta** in the **2024 Maximum Investment Levels Phase 2** proceeding before the **Alberta Utilities Commission.**
- Provided regulatory consulting services to the **BCOAPO ET AL** Intervenor Group (British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Tenants Resource & Advisory Centre and Together Against Poverty Society) in connection with numerous applications before the **British Columbia Utilities Commission**, including:
    - **FortisBC Energy Inc. (gas):**
        - Pattullo Gas Replacement Project Certificate of Public Convenience & Necessity (CPCN);
        - Biomethane Energy Recovery Charge Rate Methodology & Comprehensive Review of a Revised Renewable Gas Program;
        - Tilbury Liquefied Natural Gas Storage Expansion Project CPCN;
        - Okanagan Capacity Upgrade Project CPCN;
        - 2022 Long-Term Gas Resource Plan (integrated resource plan);
        - 2023 Demand-Side Management Expenditures Plan;
        - Interior Transmission System Transmission Integrity Management Capabilities Project CPCN;
        - 2024 to 2027 Demand-Side Management Expenditures Plan;
        - 2024 Annual Review of Delivery Rates;
        - 2023 Cost of Service Allocation & Revenue Rebalancing;
        - 2025 to 2027 Rate Setting Framework Application;
        - Okanagan Capacity Mitigation Project CPCN;
        - Regional Gas Supply Diversity Development Cost Deferral Account Recovery Application;
        - 2025 and 2026 Annual Review of Delivery Rates;
        - 2027 Annual Review of Delivery Rates; and
        - 2026 Long-Term Gas Resource Pan (integrated resource plan).

- **Pacific Northern Gas Ltd.**:
    - Salvus to Galloway Gas Line Upgrade Project CPCN;
    - West Division 2022 Revenue Requirements Application;
    - North-East Division 2022 Revenue Requirements Application;
    - 2023 to 2024 Energy Conservation & Innovation Portfolio Funding Application;
    - West Division 2023 & 2024 Revenue Requirements Application;
    - North-East Division 2023 & 2024 Revenue Requirements Application;
    - 2024 Consolidated Resource Plan (integrated resource plan);
    - 2025 to 2027 Energy Conservation & Innovation Portfolio Funding Application;
    - West Division 2025 to 2027 Revenue Requirements Application; and
    - North-East Division 2025 to 2027 Revenue Requirements Application.
- **Creative Energy Vancouver Platforms Inc.:**
    - 2021 Long-Term Resource Plan;
    - 2021 Revenue Requirements Application for the Core Steam System;
    - 2021 Application for Heating Rates for the Thermal Energy System & Cooling Rates for the District Cooling System;
    - Core Steam System Decarbonization Project CPCN;
    - Beatty-Expo Plants Redevelopment Project Final Design;
    - 2023 Revenue Requirements Application for the Core Steam System;
    - 2024 Revenue Requirements Application for the Core Steam System;
    - 2025 Revenue Requirements Application for the Core Steam System;
    - 2026 Revenue Requirements Application for the Core Steam System;
    - New Plant Premises & Interconnection Capital Expenditure Schedule;
    - 2024 Long-Term Resource Plan;
    - 2024 to 2027 Rates for Heating at South Downtown Thermal Energy System;
    - 2026 to 2027 Rates for Cooling at South Downtown Thermal Energy System; and
    - Senakw 2026 to 2027 Rates & Rate Design Application.
- **Corix Multiutility Services Inc.**:
    - Burnaby Mountain District Energy Utility 2020 to 2023 Revenue Requirements Application;
    - Burnaby Mountain District Energy Utility 2024 to 2025 Revenue Requirements Application;
    - Burnaby Mountain District Energy Utility 2026 to 2027 Revenue Requirements Application;
    - UBC Neighbourhood District Energy System 2025 to 2027 Revenue Requirements Application; and
    - Dockside Green District Energy System 2025 to 2028 Revenue Requirements Application.
- **FortisBC Inc. (electric).**:
    - 2023 to 2027 Demand-Side Management Expenditures Plan;
    - 2025 to 2027 Rate Setting Framework Application;
    - 2025 and 2026 Annual Review of Delivery Rates; and
    - 2027 Annual Review of Delivery Rates.
- **Nelson Hydro** - 2023 Revenue Requirements Application.
- **BC Hydro** - Enterprise Resource Planning Projects (S/4HANA & Stations SAP projects).
- **Insurance Corporation of British Columbia:**
    - 2021 Policy Year (2021/22 & 2022/23) Revenue Requirements Application;
    - 2023 Policy Year (2023/24 & 2024/25) Revenue Requirements Application; and
    - 2024 Financial Allocation Methodology Application.

- **British Columbia Utilities Commission:**
    - Inquiry into the Acquisition of Renewable Natural Gas by Public Utilities in British Columbia - Phase 2;
    - Inquiry into the Regulation of Hydrogen Energy Services;
    - Review of Thermal Energy Systems Regulatory Framework Guidelines Phase 2; and
    - Review of Renewable Natural Gas Definition and Accounting

- Provided regulatory consulting services on regulatory policy and revenue requirement matters to the **Consumers Coalition** (Consumers Association of Canada (Manitoba), Aboriginal Council of Winnipeg and Harvest Manitoba) in connection with the **Manitoba Hydro 2021/22 Interim Rate Application** and associated **Review & Vary Application** before the **Manitoba Public Utilities Board**.

- Provided regulatory consulting services to the **Consumers Coalition** and **Consumers Association of Canada (Manitoba)** in connection with the **Manitoba Hydro/Centra Gas Manitoba Inc. Combined Hearing Application** - before the **Manitoba Public Utilities Board.**

- Provided regulatory consulting services on regulatory policy and revenue requirement matters to the **Consumers Coalition** in connection with its **Application for an Order Requiring a Manitoba Hydro Status Update Hearing**, before the **Manitoba Public Utilities Board.**

- Provided independent expert evidence and advice on policy evaluation and practice research matters on behalf of the **Consumers Association of Canada (Manitoba)** in the **Centra Gas Manitoba Inc. Natural Gas Cost of Service Review** proceeding before the **Manitoba Public Utilities Board.**

- Provided independent expert evidence and advice on policy evaluation, customer research and stakeholder engagement matters on behalf of the **Consumers Association of Canada (Manitoba)** in the **Centra Gas Manitoba Inc. Rate Re-bundling** proceeding before the **Manitoba Public Utilities Board.**

- Conducted yearly reviews of the potential for cross-subsidy between distribution of gas and sale of gas at **Liberty Utilities (Gas New Brunswick) LP** during 2021, 2022, 2023, 2024 and for the **New Brunswick Energy & Utilities Board.** Provided expert testimony on the 2022 to 2024 cross-subsidy review reports and findings and recommended improvements to minimum filing requirements to the **New Brunswick Energy & Utilities Board.**

- Provided independent expert evidence and testimony to the **Nova Scotia Utility and Review Board** regarding **Nova Scotia Power Inc.'s 2021 Back-Up/Top-Up Amendment Application** with respect to pricing and terms and conditions of service of municipal electric utilities.

- Provided advisory services to **Efficiency Manitoba** in connection with its **2020-2023 Efficiency Plan** filing to the **Manitoba Public Utilities Board**, including regulatory on-boarding, filing review process design and strategic filing preparation advice.

- Provided independent expert evidence and testimony on regulatory policy, financial reserve targets and revenue requirement matters on behalf of the **Consumers Association of Canada (Manitoba)** in the **Centra Gas Manitoba Inc. 2019/20 General Rate Application** proceeding before the **Manitoba Public Utilities Board.**

- Provided independent expert evidence and testimony on regulatory policy, financial reserve targets and revenue requirement matters on behalf of the **Consumers Coalition** in the **Manitoba Hydro 2019/20 Rate Application** proceeding before the **Manitoba Public Utilities Board.**

- Conducted an independent review of the **2019/20 Chestermere Utilities Inc. rate proposal** (water, sanitary & storm services) and associated financial implications for the **City of Chestermere** (acting as the regulator).

- Provided independent advice to the **Consumers Association of Canada (Manitoba)** on case strategy and the capital management plan in connection with the **Manitoba Public Insurance 2020 General Rate Application** before the **Manitoba Public Utilities Board.**

- Conducted a review and made recommendations on the implementation of a revised **internal cost allocation methodology** (allocation of corporate and shared service costs) for **Corix Infrastructure Inc.** (a leading provider of energy, water & wastewater utilities for small to medium-sized communities across North America).
- Provided independent advice to an Industrial Intervenor on the Advanced Metering Infrastructure (AMI) project in connection with **New Brunswick Power Corporation 2018/19 General Rate Application** before the **New Brunswick Energy & Utilities Board.**
- Provided independent advice to legal counsel for an intervenor with respect to case strategy, evidence evaluation and revenue requirement matters in connection with the **Northwest Territories Power Corporation 2016-2019 General Rate Application** before the **Northwest Territories Public Utilities Board.**
- Provided strategic advice on financial reporting matters to the **Manitoba Department of Health** as part of the Health Sector **Financial Budgeting & Reporting Improvement Project.**

MANITOBA HYDRO & CENTRA GAS **1999 – 2017**

Acting President and Chief Executive Officer **September to December 2015**

- Responsible for the **overall executive leadership** of one of the largest integrated electric and natural gas utilities in Canada with over $20 billion in assets, $2.3 billion in revenues, 568,000 electricity and 277,000 natural gas customers and over 6,000 employees.
- **Key leadership accountabilities** included strategy and business plan implementation, executive support to the Manitoba Hydro-Electric Board (MHEB), organizational and people leadership, financial, operational and performance leadership and public relations and stakeholder relationship management.
- Maintaining progress on **delivery of key strategic objectives, execution on major capital projects** and effective transition to the newly appointed CEO while simultaneously managing several complex finance & regulatory projects in the on-going role as CFO.

Vice-President, Finance & Regulatory Affairs and Chief Financial Officer **2013 – 2017**

- Responsible for the **executive leadership** of the **Finance & Regulatory Affairs business unit** (Controller, Treasury, Rates & Regulatory Affairs, Financial Planning and Corporate Risk Management) and **Manitoba Hydro International** (professional consulting and project management services to energy sectors world-wide).
- Member of the **Executive Committee** that actively collaborated in the **management of the corporation** and the formation, revision and achievement of the **corporate strategic plan** and establishment of **business unit goals & strategies** that align with the strategic objectives of Manitoba Hydro. Led, developed and mentored a diverse team of senior professionals as well as cross-disciplinary project teams.
- Initiated target setting process and collaborated with the executive team to develop a **multi-year budgeting strategy** to substantially reduce the growth in operating expenditures. Championed the establishment of an overall **corporate asset management framework** and further development of systems to improve the planning and prioritization of sustaining capital expenditures in the generation, transmission, distribution and corporate functions.

- Guided the development of **corporate financial targets** and the **long-term financial forecast** as well as corporate operating, capital and financing plans that are consistent with the overall objectives of the Corporation and obtained endorsement from the Audit Committee and MHEB. Initiated and provided executive oversight to a **comprehensive review of corporate financial targets** to determine if they continued to be appropriate during a period of extensive capital investment of over $17 billion.
- Provided policy guidance to support the development of increasingly sophisticated **financial models to provide scenario analysis** (over 15,000 financial projections) on key financial variables (water flows, export prices, interest rates and capital costs) to evaluate the adequacy of financial targets and financial reserves and forecast the long-term rate impacts of major capital projects.
- Provided executive oversight to the development and execution of **financing strategies** and plans to obtain long-term debt financing in the order of $1.5 billion to $2 billion annually and to effectively manage the corporation's liquidity, foreign exchange and interest rate risks. Provided policy guidance to treasury staff to develop a more cost-effective approach to **manage significant risk exposure from US currency fluctuations** on export revenues and to develop an **alternate debt management strategy** to retire debt and improve the financial outlook.
- Directed the **financial** and **management reporting** and **corporate risk management functions** and provided regular reports on the financial results and risks of the corporation to Executive Committee, Audit Committee and MHEB. Executive accountable to oversee the **transition** from Canadian Generally Accepted Accounting Principles (CGAAP) to **International Financial Reporting Standards** (IFRS) for financial reporting purposes and the strategy to use IFRS for rate-setting purposes.
- Chair of the **Corporate Risk Management** and **Rates Review committees**. Member of the Export Power and Gas Supply **Risk Management committees** and the **Corporate Asset Management Executive Council**. Member and **Treasurer of the Wuskwatim** and **Keeyask Limited Partnership Boards** working closely with Indigenous partners.
- **Chief regulatory officer** and provided executive direction with respect to regulatory affairs before the Manitoba Public Utilities Board (MPUB) (Manitoba Hydro & Centra Gas) and National Energy Board (Minell Pipelines). Represented the corporation as **executive policy witness** and chief regulatory strategist for several significant electric and gas regulatory proceedings before the MPUB, as follows:
    - The **2016 Electric Cost of Service Methodology Review** before the MPUB to review the methodology underpinning the allocation of a $2 billion revenue requirement and $20 billion rate base among 568,000 customers.
    - The **2015 Electric General Rate Application** before the MPUB which included final approval of interim rates for 2014/15 and rates for 2015/16 as well as the establishment of a process to review interim rates for 2016/17. Applied a top-down strategy driven approach and drove the transformation of rate applications to increase revenues, ensure the on-going financial sustainability of the corporation, maintain reliable service and stable rates - while balancing the interest of ratepayers with the financial integrity of the corporation.
    - The **2015 Cost of Gas Application** before the MPUB and directed the development of the regulatory strategy and principles associated with the prudence review and recovery of additional gas costs of $46 million incurred during the record cold winter weather of 2013/14.
    - The finance witness panel at the **2014 MPUB review of the Need For and Alternatives To** (NFAT) Manitoba Hydro's proposed Major Generation and Transmission capital projects involving a planned investment of over $17 billion. The finance panel witness responsibilities included the potential impact on customers rates, financial outlook and financial risk associated with the planned investments; and
    - The **2013 Centra Gas General Rate Application** before the MPUB to set gas costs and non-gas revenue requirement for 2013/14.

Corporate Controller, Controller Division **2008 - 2013**

- Directed the **preparation** of the **electric** and **gas revenue requirement filings** and represented the corporation as a **senior subject matter witness** at several MPUB **electric rate hearings** between 2008 and 2013 (2008/09, 2009/10, 2010/11 & 2011/12, 2012/13 & 2013/14 GRA's) providing witness testimony on financial results, long-term financial forecast, operating & capital cost forecasts, other revenue requirement components as well as implementation of depreciation studies and IFRS accounting policies for rate-setting purposes.
- Oversaw the development of the **long-term financial forecast** and the **coordination of the consolidated operating cost** and **capital expenditure forecasts** and presentation to the Audit Committee and MHEB.
- Led the **financial** and **management reporting functions** of the corporation and managed interaction with the provincial Comptroller's Division and external auditors. Guided the **provision of financial services** to the **business unit** management teams.

Corporate Treasurer, Treasury Division **2006 - 2008**

- Led the development of **debt management** and **financing strategies** to obtain corporate financing requirements and effectively manage the corporation's liquidity, foreign exchange and interest rate risks. Provided testimony as a **senior subject matter expert** at the 2007/08 & 2008/09 Centra GRA on rate base, return on equity, working capital allowance, finance expense and debt management.
- Managed interaction with **credit rating agencies**, the provincial Treasury Division and investment banking institutions.
- Guided **cash management**, cash forecasting and **credit risk management** functions and the administration of banking arrangements.

Manager, Regulatory Services Department **1999 - 2006**

- **Managed** the preparation of **numerous regulatory applications**, **filings** and **reports** to the **MPUB**, the post-application/pre-hearing processes, the public hearing process and the interpretation and compliance with MPUB decisions from 1999 to 2006 (types of regulatory proceedings/matters include: general rate applications, commodity cost prudence reviews/pass throughs, franchise expansions & feasibility tests, natural gas broker service improvements & stakeholder engagement process, pipeline safety, integrity & construction methods, customer disconnections, acquisition of a natural gas cooperative).
- Responsible for **regulatory planning/administration** and providing **recommendations** to **senior management** on regulatory **strategy, issues** and **procedural matters**. Acted as a liaison with MPUB staff and advisors.
- Represented the corporation as a **subject matter witness** at several MPUB **natural gas rate hearings** between 2000 and 2006 (2000 Interlake expansion, 2003/04 GRA, 2004/05 Cost of Gas, 2005/06 & 2006/07 GRA, 2007/08 & 2008/09 GRA), providing witness testimony on revenue requirements, rate base, cost of capital/return on equity, capital structure, lead-lag study, financial feasibility tests and procedural matters.
- Oversaw the development of the **Quarterly Primary Gas application** and associated processes in 2000 to adjust the cost of gas from western Canada on each gas quarter using an efficient and streamlined regulatory approval process.

CENTRA GAS MANITOBA INC. **1994 - 1999**

Senior Coordinator, Regulatory Services Department **1997 - 1999**

- Responsible for the **coordination** and **preparation** of **regulatory applications, filings** and **reports** to the MPUB (types of regulatory proceedings/issues include: 1998 general rate application, commodity cost prudence reviews/pass throughs, franchise expansion & feasibility test reviews, debt & equity issues, accounting policy selection, depreciation rates, intercompany cost allocations & affiliate transactions).
- Provided **direction** to **regulatory staff** and **internal clients** with respect to regulatory process and procedural matters, the preparation of responses to MPUB decisions, directives and requests and participated in the **preparation of evidence** and **witnesses** for public hearings.

Senior Financial Analyst, Financial & Accounting Services Department **1994 - 1997**

- Acted as internal expert and **provided support** to **company witnesses** at MPUB public hearings with respect to business case and feasibility assessments as well as financing, capital structure and cost of capital/rate of return and feasibility test matters (1995 & 1997 GRA's). Developed the Centra **return on equity formula** proposal for the 1995 GRA.
- Provided advice and assisted in the **preparation of business cases** with internal management and project teams to support business expansion and growth opportunities, capital expenditures and operating decisions. Coordinated all aspects of **financial analysis** and **feasibility assessments** including the development of financial models, investment evaluation criteria and the presentation of results to internal management.

PRICE WATERHOUSE, CHARTERED ACCOUNTANTS (Winnipeg Office) **1988 - 1994**

Assistant Manager, Financial Advisory Group **1990 – 1994**

- Acted as **accounting & finance advisor to the MPUB** between 1990 and 1994 on several Centra Gas regulatory applications (including 1990 GRA, 1991 GRA, 1992 GRA & 1993 GRA), a 1994 Manitoba Hydro GRA and a Stittco Utilities Manitoba (propane) 1991 GRA. Drafted numerous regulatory decisions for the MPUB during that timeframe. Provided advice on all aspects of revenue requirements including operating costs, depreciation, finance expense, income & other taxes, rate base, working capital, capital structure and cost of capital/return on equity.
- Provided extensive **consulting advice to the MPUB** and drafted regulatory decisions on **capital structure** and **cost of capital/return on equity** matters including the last comprehensive decision on the allowed capital structure and return on equity for Centra Gas in 1994.
- Prepared **business valuations**, conducted business reviews for acquisition and divestiture purposes and prepared **quantifications of losses** or **damages** for use in litigation proceedings.

Audit Senior, Audit & Business Advisory Group **1988 - 1990**

- Provided **audit** and **business advisory services** to clients in several industries, including real estate, investment dealing and agriculture, as well as public sector clients.