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September 21, 2023

Via Email

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

Attention: Jo Galarneau
Executive Director and Board Secretary

Dear Ms. Galarneau:

Re: Newfoundland Power Inc. - 2024 Capital Budget Application
- Report of Midgard Consulting Inc. dated September 21, 2023

Further to the above-captioned, enclosed please find the Utility Management Responsibility Report prepared by Midgard Consulting Incorporated on behalf of the Consumer Advocate, which we forward for filing with the Board.

Yours truly,

Dennis Browne, KC
Consumer Advocate

Encl.
/bb

cc **Newfoundland Power Inc.**
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Utility Management Responsibility Report

Prepared on Behalf of the Newfoundland & Labrador Consumer Advocate

SUBMITTED BY

Midgard Consulting Incorporated

DATE

September 21, 2023

Midgard, established in 2009, provides consulting services across the electrical power and utility sector. Midgard's principals and staff have direct experience in project development, design, contract procurement, finance, construction, and operations. This combined experience has translated into mandates in project due diligence, lender's technical advisor, loan guarantee assessments, and Independent Engineer roles in Canada, the United States, and internationally. Midgard has worked for developers, utilities, government agencies, and both project lenders and equity providers.

Midgard's team has extensive experience modelling fuel sources, creating energy yield estimates, reviewing contracts, reviewing pro-formas, and assessing project risks from a construction, operations, and financial perspective.

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Revision	Description	Date
0	Released by Midgard for submission into evidentiary record.	September 21, 2023
1	Revision for submission into evidentiary record.	September 21, 2023

REPORT SIGN-OFF

Prepared By: ______________________ ____________

Matthew Matusiak, P.Eng.; Midgard Consulting Inc. ***Date***

Prepared By: ______________________ ____________

Peter Helland, P.Eng.; Midgard Consulting Inc. ***Date***

Checked By: ______________________ ____________

Chris Oakley, P.Eng.; Midgard Consulting Inc. ***Date***

Approved By: ______________________ ____________

Peter Helland, P.Eng.; Midgard Consulting Inc. ***Date***

NOTE: ORIGINAL HARD COPY IS SIGNED, SEALED, AND RETAINED ON FILE BY MIDGARD

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LIST OF ACRONYMS

ACM	Advanced Capital Module
BC	British Columbia
BCUC	British Columbia Utilities Commission
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
CEJC	Capital Expenditure Justification Criteria
CNL	Canadian Nuclear Laboratories
COS	Cost of Service
CPCN	Certificate of Public Convenience and Necessity
CRBF	Change in Risk Benefit Factor
CVF	Corporate Value Framework
DSC	Distribution System Code
DSP	Distribution System Plan
EBT	Electronic Business Transaction
EGBC	Engineers and Geoscientists of BC
EIT	Engineer-In-Training
ERM	Enterprise Risk Management
EV	Electric Vehicle
FBC	FortisBC Inc.
FEED	Front End Engineering Design

FEI	FortisBC Energy Inc.
GHG	Greenhouse Gas(es)
GRA	General Rate Application
HONI	Hydro One Networks Inc.
ICM	Incremental Capital Module
IFRS	International Financial Reporting Standard
IR	Incentive Regulation
IRR	Internal Rate of Return
IRM	Incentive Rate-setting Mechanism
LTC	Leave to Construct
MAAD	Mergers, Amalgamations, Acquisitions and Divestitures
MFR	Minimum Filing Requirement(s)
MH	Manitoba Hydro
MMTP	Manitoba Minnesota Transmission Project
MPUB	Manitoba Public Utilities Board
MRP	Multi-year Ratemaking Plans
NLH	Newfoundland and Labrador Hydro
NP	Newfoundland Power
NPV	Net Present Value
NLPUB	Newfoundland Board of Commissioners of Public Utilities
NSPI	Nova Scotia Power Inc.
NSUARB	Nova Scotia Utility and Review Board
O&M	Operation and Maintenance
OEB	Ontario Energy Board
OFA	Ontario Finance Authority
PACA	Participant Assistance/Cost Award Guidelines
PBR	Performance-Based Regulation
PHB	Port Hawkesbury Biomass
PCB	Polychlorinated Biphenyl(s)
RCIA	Residential Consumers Intervener Association
RRR	Reporting and Record Keeping Requirements
RSC	Retail Settlement Code
SAIDI	System Average Interruption Duration Index

SAIFI	System Average Interruption Frequency Index
SQR	Service Quality & Reliability
SSSC	Standard Supply Service Code
SME	Subject Matter Expert(s)
T-SAIDI	Transmission System Average Interruption Duration Index
T-SAIFI	Transmission System Average Interruption Frequency Index
TSC	Transmission System Code
UCA	Utilities Commission Act
YEC	Yukon Energy Corporation

1 INTRODUCTION

Midgard Consulting Incorporated ("Midgard") has been retained by the Consumer Advocate to provide an opinion on utility capital budgets and regulatory approvals.

1.1 Scope of Review

In a letter dated 18 July 2023, the Consumer Advocate provided a scoping letter that outlined questions pertaining to regulators in North America. The following is a table of concordance outlining the contents of this report based off the scoping letter contents:

Table 1: Consumer Advocate Scoping Letter Questions[1]

Scoping Letter Inquiries	Report Section
How do regulatory boards elsewhere implement and apply capital budget envelopes or similar mechanisms?	Section 3
How do regulatory boards elsewhere ensure that the assets proposed for refurbishment/replacement are appropriately prioritized and included in the Capital Expenditure ("CAPEX") investment list?	Section 4
How do regulatory boards elsewhere ensure that CAPEX investments yield the anticipated outcomes, (e.g., customer service and enhanced reliability[2] and reduced operating and maintenance costs) and how are utility management practices employed to measure and quantify enhancements in customer service and reliability stemming from capital projects?	Section 5
How are utility management practices used to quantify improvements in cost savings in operational and maintenance costs resulting from a capital project?	Section 6
How are utility management practices used to quantify the risk of not proceeding with a capital project?	Section 7
What role does SAIDI/SAIFI play in the regulator's analysis of the annual CAPEX budget, and when are SAIDI/SAIFI objectives expected to be realized or accomplished?	Section 8

[1] A copy of the scoping letter can be found in Appendix F:.

[2] While some utilities consider customer satisfaction and reliability as separate metrics, this report treats customer service and reliability as being aspects of the same metric. The report will examine how methodologies quantify enhancements in reliability resulting from capital projects. The scope of this report excludes the broader interpretation of customer service to include customer satisfaction surveys which involve metrics related to customer engagement and customer contact experience (e.g., bill accuracy, call center response times, ability of call centers to address customer queries or complaints). For example, Manitoba Hydro obtains customer service metrics from its Customer Values Assessment Study. This study gathers information on customer contact & service experiences, billing and payments, and perceptions of Manitoba Hydro (Source: Manitoba Hydro 2023/24 & 2024/25 General Rate Application, *Report on Customer Values Assessment Study*, Tab 10, MFR-12, Attachment 1. Link)

1.2 Cost of Service and Performance-Based Regulation Models

Midgard was asked to explore Cost of Service ("COS") and Performance-based Regulation ("PBR") regulatory jurisdictions in this report:

- Cost of Service: the regulator determines the Revenue Requirement—i.e., the "cost of service"—that reflects the total amount that must be recovered in rates for the utility to recover its costs and earn a reasonable return.[3]
- Performance-based Regulation: a regulatory approach that focuses on desired, measurable outcomes, rather than prescriptive processes, techniques, or procedures. Performance-based regulation leads to defined results without specific direction regarding how those results are to be obtained.[4]

1.3 Transmission and Distribution Utilities

During its jurisdictional review Midgard reviewed two types of utilities that mirror the two relevant utilities in Newfoundland and Labrador:

1. Generation and Transmission-based (or Transmission-only) Utilities: utilities responsible for generating electricity and then transmitting bulk electricity through a network of high voltage transmission lines and infrastructure over long distances across a wide geographical area. In certain cases, the reviewed utilities were Transmission Only utilities, but they deal with the same issues pertaining to larger capital investments similar to generation and transmission utilities.
2. Distribution-based Utilities: downstream of a transmission utility, these utilities are responsible for the final stage of delivering electricity to end-users, typically residential, commercial and small industrial customers. Distribution utilities operate at lower voltage levels than transmission utilities and manage the local distribution networks[5] that connect smaller consumers to the bulk electricity supply.

A substantial proportion of the capital investment portfolios typical of generation-based utilities comprise a relatively small number of comparatively large discrete capital projects. In contrast, the capital investment portfolios of distribution-based utilities tend to incorporate a larger number of smaller capital investments that may be bundled together into capital investment programs. Transmission utilities generally exhibit the

[3] National Association of Regulatory Utility Commissioners, Tariff Development I: The Basic Ratemaking Process, Slide 3. Link.

[4] United States Nuclear Regulatory Commission, Performance-based Regulation. Link.

[5] Infrastructure such as distribution lines, transformers, substations, and meters.

same characteristics as distribution utilities with the exception that major projects such as transmission system expansions (e.g., new transmission lines) are large discrete capital projects. .

1.4 Methodology

A jurisdictional scan (via a desktop review) was conducted to identify standard regulatory processes and best practices implemented by provincial regulatory boards across Canada.[6] Table 2 provides an overview of jurisdictions and regulatory boards reviewed as part of this activity, including reference to the capital approval processes used in each.

Table 2: Overview of Jurisdictions and Regulatory Boards

Canadian Jurisdiction	Capital Approval Process			Overview Summary
	Annual Budget	Cost of Service	Performance-Based Regulation	
British Columbia		✓	✓	Appendix A:
Manitoba		✓		Appendix B:
Ontario		✓	✓	Appendix C:
Newfoundland	✓			Appendix D:
Nova Scotia	✓			Appendix E:

Based on the jurisdictional scan key elements of the capital approval procedures for electric utilities within each of the Canadian jurisdictions outlined in Table 2 are explored to answer the questions posed by the Consumer Advocate.

[6] Since the selected Canadian provinces provide a broad and representative sample of regulatory practices across Canada, the Canadian territories (i.e., Yukon, Northwest Territories, and Nunavut) and Quebec were not deemed necessary to include in the jurisdictional scan.

2 QUALIFICATIONS OF AUTHORS

Peter Helland, Christopher Oakley, and Matthew Matusiak are Professional Engineers at Midgard. Collectively, as the authors of this report, they possess the relevant background, experience, and expertise necessary to prepare the scope of evidence the Consumer Advocate has engaged them to provide.

The authors of this report acknowledge their duty of independence in providing their professional opinions to the NLPUB. Although engaged by the Consumer Advocate to carry out an unbiased review of the CAPEX budget submission and approval processes applicable to regulated utilities in different Canadian jurisdictions, the authors of this report do not advocate for the Consumer Advocate or any other party. The authors are accountable for the entirety of the content and all opinions presented in this evidence, which have been prepared in alignment with their acknowledged duty of independence. If required to provide oral or written testimony, the authors will offer testimony in accordance with their duty of independence.

2.1 Peter Helland, M.Sc., MBA, P.Eng.

Peter Helland is a co-founding Principal of Midgard Consulting Incorporated, has worked at Midgard for 14 years and was Midgard's CEO from its founding in 2009 until the end of 2020.

Mr. Helland received a Bachelor of Applied Science in Systems Engineering and Master of Applied Science from Simon Fraser University in 2005 and 2007 respectively, and a Master of Business Administration from the Sauder School of Business in 2005. In 2019 he received a certificate in asset management from NAMS Canada.[7]

Mr. Helland's present professional practice primarily lies in the domains of engineering, regulatory and business consulting. He was the founding Director of the Residential Consumers Intervener Association ("RCIA"), an entity whose creation was initiated by the BC Utilities Commission to provide fair, transparent, and non-discriminatory representation of the interests of all residential utility consumers in the Province of BC in regulatory proceedings heard by the BCUC.

Mr. Helland's utility regulation areas of expertise include asset management, risk management, resource options planning, condition assessment, project development, project management and facilities siting. He regularly participates in revenue requirement proceedings, rate design and cost of service proceedings, resource plan reviews, and generation, transmission & distribution facility need and siting proceedings. His regulatory practice clients include Canadian regulators, utilities and customer groups.

[7] NAMS Canada is a subsidiary of the Institute of Public Works Engineering Australasia. NAMS Canada has a mandate to assist Canadian and North American local governments and public works entities to improve their public infrastructure assets management and offers courses in various aspects of asset management.

Mr. Helland has been involved in numerous proceedings heard by the BC Utilities Commission ("BCUC"), including BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirement Application, BC Hydro's Fiscal 2021 to 2022 Revenue Requirements Application, BC Hydro's 2021 Integrated Resource Plan, and numerous facility applications; FortisBC's Long Term Electric Resource Plan, 2021 & 2022 Rate Reviews; and Cost of Service, Revenue Requirement and Capital Project Applications filed by numerous other regulated electricity utilities.

Much of Mr. Helland's regulatory work prior to RCIA involved reviewing utility distribution system plans and transmission system plans for the Ontario Energy Board, with specific focus on asset management, condition assessment, capital spending and risk management. Mr. Helland was part of an audit team appointed by the Alberta Utilities Commission to review a major transmission project that went considerably over budget and provided an expert report on the root causes of the spending overruns.

Mr. Helland provided a two-day seminar on asset management, risk and "Power Systems 101" for the Manitoba Public Utilities Board and supported the Manitoba PUB in its review of Manitoba Hydro's 2017-19 General Rate Application ("GRA") capital spending plans. Mr. Helland was also a lead author of an expert report commissioned by the Newfoundland and Labrador Public Utilities Board ("NLPUB") to review and recommended revisions to the capital budget approval guidelines utilized by the two major electrical utilities in that Province.

Mr. Helland has provided services to multiple government agencies and government utilities. He has provided generation project deliverability and financial capability assessments to the Ontario Financing Authority ("OFA") for its Aboriginal Loan Guarantee program and is presently providing support to both the OFA and the Ontario Ministry of Energy for the $2 billion Wataynikaneyap Transmission Project, which is the 13th of 15 projects Midgard has undertaken for the OFA. Mr. Helland has provided resource development, transmission option planning, project siting and reliability assessment services for the Yukon Energy Corporation and the Yukon Development Corporation. Notably, he led the technical, economic, and environmental evaluation for Yukon's "Next Generation Project" for the Yukon Development Corporation that was looking to site a major greenfield hydroelectric facility in Yukon. He also architected the Alberta Department of Energy project to assess the capacity of the aggregated Alberta distribution systems to uptake incremental distributed energy resources. He also helped prepare a system development plan for Northwest Territories Power Corporation and supported an analysis for the Bonneville Power Administration of the US Department of Energy into the expected power system and hydrology consequences of terminating the Columbia River Treaty. He has provided generation resource planning and transmission system support planning services to SaskPower. He provided negotiation and technical support to Nisga'a Lisims Government ("NLG") in negotiations with an electric utility.

His work for Investor-owned utilities and independent power producers includes helping prepare the initial cost of service revenue requirement application for Ocean Falls Hydro that was accepted by the BCUC. He helped prepare FortisBC's (FBC) 2011 Resource Plan and BCUC Section 71 filing for the Waneta Expansion capacity purchase. He has provided acquisition due diligence and project development support to independent power producers in BC and Alberta. He was responsible for hands-on operation and maintenance of the 10 MW McNair Creek Hydro plant on Howe Sound in coastal BC.

Prior to Midgard, Mr. Helland worked at Oceanworks International, where he was the Senior Electrical Engineer and ultimately the Project Manager that delivered a first-in-class submarine rescue vehicle to the United States Navy for their nuclear submarine fleet and other NATO compatible submarines. During that time, he gained exposure to asset management, engineering design, construction, operations, maintenance, process management, risk and risk management, failure modes and effects analysis, asset lifecycles, asset inspection, fleet sparing, and quality control and assurance systems.

Mr. Helland is a Professional Engineer registered in the Province of BC and Yukon Territory. Mr. Helland is the chair of the Investigative Committee for Engineers and Geoscientists of BC ("EGBC") which is responsible for investigating professional practice and ethics violation complaints. Mr. Helland is also a trustee of the Vancouver Maritime Museum and past chair of the Board of Burnaby Family Life.

2.2 Christopher Oakley, P.Eng.

Christopher Oakley has worked in the utility and energy business for 37 years since receiving his BSc in Electrical Engineering with a minor in Computer Engineering from the University of Calgary in 1986.

He was a founding principal of Midgard Consulting in 2009 and has been working with Midgard as a consultant for the past 14 years. His work with Midgard covers a broad range of utility and energy matters, from utility regulation and energy policy to electric system planning, generation, transmission, distribution and communications project development, financing, and operations.

Much of Mr. Oakley's current practice is focused on utility rate regulation, but he continues to provide consulting services on more technical matters, such as power system modeling, generation, and T&D projects & operations, and powerline electrical effects.

His utility regulation areas of expertise include utility capital planning, asset management planning, resource planning, operating good practice, project development, project management and facilities siting. He regularly participates in revenue requirement proceedings, rate design and cost of service proceedings, resource plan reviews, and generation, transmission & distribution facility need and siting proceedings. His regulatory practice clients include Canadian regulators, utilities and customer groups.

Mr. Oakley regularly provides expert evidence and application review services to the British Columbia Residential Consumer Intervener Association (RCIA) in proceedings heard by the BC Utilities Commission (BCUC), including: BC Hydro's F23-F25 Revenue Requirement Application, 2022 RRA, 2021 Integrated Resource Plan, and numerous facility applications; FortisBC's Long Term Electric Resource Plan, 2021 & 2022 Rate Reviews; and Cost of Service, Revenue Requirement and Capital Project Applications filed by numerous regulated electricity and thermal energy services utilities.

Mr. Oakley has provided Transmission and Distribution System Development Plan, Asset Management Plan and Operational Expense review services to the Ontario Energy Board in more than 20 proceedings; he has provided Transmission project audit services to the Alberta Utilities Commission; and he provided capital project, asset management and risk management review services to the Manitoba Public Utilities Board in Manitoba Hydro's 2017/18 and 2018/19 General Rate Application (GRA). He has reviewed capital refurbishment and decommissioning applications and provided expert evidence for four (4) hydroelectric projects being reviewed by the Nova Scotia Utility and Review Board. He has provided capital budget guideline upgrade recommendations to the NLPUB, and has reviewed multiple applications to construct, modify or decommission international transmission lines for the Canadian Energy Regulator (formerly the National Energy Board), including Manitoba Hydro's 500 kV Manitoba Minnesota Transmission Project ("MMTP").

Mr. Oakley has provided services to multiple government agencies and government utilities. He has provided generation and transmission project deliverability and financial capability assessments to the Ontario Financing Authority ("OFA") for its Aboriginal Loan Guarantee program and is presently providing support to both the OFA and the Ontario Ministry of Energy for the $2 billion Wataynikaneyap Transmission Project, which is the 13th of 15 projects Midgard has undertaken for the OFA. Mr. Oakley has provided resource development, transmission planning and reliability assessment services for the Yukon Energy Corporation and the Yukon Development Corporation. He participated in an Alberta Department of Energy project to assess the capacity of the aggregated Alberta distribution systems to uptake incremental distributed energy resources. He also helped prepare a system development plan for Northwest Territories Power Corporation and did analysis for the Bonneville Power Administration of the US Department of Energy into the expected power system and hydrology consequences of terminating the Columbia River Treaty. He has provided generation resource planning services to SaskPower. He provided negotiation and technical support to Nisga'a Lisims Government (NLG) in negotiations with electric utilities and energy pipeline developers, and helped NLG develop its broadband communication utility, Lisims Communications. He is a member of the Surrey City Energy Expert Rate Review Panel and helped prepare a Cost-of-Service review and update for the City of Vancouver's Neighbourhood Energy Utility.

His work for investor-owned utilities and independent power producers includes preparing the initial cost of service revenue requirement application for Ocean Falls Hydro (which included development of a hybrid pre-regulation and post-regulation depreciation schedule for existing and new assets). He helped prepare FortisBC's (FBC) 2011 Resource Plan and the BCUC Section 71 filing for the Waneta Expansion capacity purchase. He has provided acquisition due diligence, project development and EPA renewal negotiation support to independent power producers in BC, Alberta, Quebec, Washington State, Idaho, and California. He was co-owner responsible for hands-on operation and maintenance of the 10 MW McNair Creek Hydro plant on Howe Sound in coastal BC.

Mr. Oakley's last corporate role before co-founding Midgard was Vice President of Canadian Hydro Development with Brookfield Renewable Power. Prior to that he was Director of Engineering at SNC-Lavalin ATP, SNC's global T&D centre of excellence. Before that he held several roles with Aquila Networks Canada and its predecessors Utilicorp & West Kootenay Power, including Manager of Asset Deployment, Director of Power Supply and Generation (which included operation of 1000 MW of hydro plants on the Columbia, Kootenay and Pend Oreille Rivers, system control and dispatch) and Director of Revenue Management. Prior to that he was System Planning Manager at the Transmission Administrator of Alberta (predecessor of the Alberta Electric System Operator). Mr. Oakley spent the first 12 years of his professional career at TransAlta Utilities Corporation, where his roles included bulk system planning, transmission projects, substation projects, telecontrol, and inductive coordination.

Mr. Oakley has represented the Alberta Transmission Administrator, TransAlta Utilities and West Kootenay Power on the Western Electric Coordinating Council's (WECC) Planning Committee and Technical Studies Subcommittee and is co-author of the WECC's Off Nominal Frequency Load Shedding program. Mr. Oakley represented the WECC (2 Canadian Provinces, 14 US States and Baja California Norte Mexico) on the North American Electric Reliability Council (NERC) Reliability Assessment Subcommittee (RAS).

Mr. Oakley is Chair of the Board of Directors of the Traditional Learning Society of British Columbia, which oversees the 200 student Traditional Learning Academy campus and the 1,200 student TLA Online distance learning school.

Mr. Oakley is registered as a Professional Engineer in the Provinces of BC and Alberta.

2.3 Matthew Matusiak, P.Eng.

Matthew Matusiak is a Professional Engineer at Midgard. Mr. Matusiak is licensed as a Professional Engineer in the Canadian provinces of British Columbia and Ontario.

Mr. Matusiak received a Business Administration Diploma from the University of the Fraser Valley in 2013 and a Bachelor of Science in Electrical and Computer Engineering from the University of Victoria in 2019.

Mr. Matusiak's professional activity centers around the fields of engineering and regulatory affairs. He also works as a consultant for the RCIA, an entity whose creation was initiated by the BCUC to provide fair, transparent, and non-discriminatory representation of the interests of all residential utility consumers in the Province of BC in regulatory proceedings heard by the BCUC. As a consultant for RCIA, he frequently engages in proceedings related to revenue requirements, rate structure and cost analysis, evaluations of resource plans, and proceedings concerning the need and location of generation, transmission, and distribution facilities, managing project teams that include senior Midgard staff to intervene in BCUC proceedings involving major British Columbia utilities.

Mr. Matusiak has provided services to multiple agencies and utilities. Mr. Matusiak assisted in preparing intervener evidence for the Alberta Utilities Commission, intervening in EPCOR Distribution and Transmission Inc.'s ("EPCOR") 2023-2025 TFO Tariff Application, evaluating the expected life and annual replacement rate of EPCOR's transformer fleet through statistical analysis, proposing reductions to EPCOR's capital expenditure portfolio. By simulating electrical power systems studies, analyzing power flow, short-circuit currents, and voltage stability, Mr. Matusiak has also helped address concerns of the Yukon Energy Corporation ("YEC") that arose with the increased penetration of intermittent generation into the Yukon electrical grid. He is also serving as a project manager for YEC, overseeing technical consultants, tracking project budgets, preparing status reports, engaging in regular discussions with other project managers, and encompassing responsibilities related to the development and control of construction plans, procurement activities, vendor selection, as well as construction and commissioning activities for a 2 MW solar generation installation. Mr. Matusiak provides assessments of project feasibility and financial capacity for electricity generation projects to the OFA, specifically focusing on its Aboriginal Loan Guarantee program. Currently, he is providing support to both the OFA and the Ontario Ministry of Energy for the $2 billion Wataynikaneyap Transmission Project.

Prior to his time at Midgard, Mr. Matusiak worked at Canadian Nuclear Laboratories ("CNL") as a Project Engineer-In-Training ("EIT") where his role involved extensive collaboration with design participants, operations engineering teams, technical experts, and nuclear operators to gather essential technical input required to fulfill project and client needs. He played a pivotal role in providing technical support throughout various project phases, from design and procurement to construction and commissioning. He also actively contributed to overseeing design, construction, and commissioning activities while evaluating equipment selection options.

2.4 About Midgard Consulting Incorporated

Midgard is a federally incorporated Canadian company with its main office in British Columbia ("BC"). Midgard has been providing consulting services to the electrical power and utility industry since 2009. Midgard's work has an emphasis on strategic planning, regulatory & policy support, transmission and distribution, electricity generation engineering services (renewable and non-renewable), and energy market planning. Midgard's founding principals and senior staff have over 150 years of cumulative experience in the electric power and utility industry, and a broad spectrum of expertise and knowledge gained in numerous Canadian and international jurisdictions.

In 2020, Midgard was retained as an expert consultant by the NLPUB to undertake an evaluation of the NLPUB's current Capital Budget Application Guidelines ("NLPUB Guidelines"). In accordance with its mandate, Midgard conducted various tasks, including reviewing the existing Guidelines and pertinent documentation, engaging with stakeholders to identify issues and areas of concern, conducting a comprehensive survey of eight Canadian jurisdictions to discern prevalent regulatory procedures and exemplary practices employed by provincial regulatory boards across the country, juxtaposing the existing Guidelines with industry and regulatory best practices, presenting the identified outcomes to stakeholders and addressing their inquiries. Finally, Midgard produced an expert report for the Board, which helped inform the Board's decision to amend the previous Capital Budget Guidelines and which led to the provisional guidelines dated January 2022, currently in place as of the writing of this report.[8]

[8] Newfoundland & Labrador Board of Commissioners of Public Utilities, *Capital Budget Application Guidelines* (Provisional). Link.

3 CAPITAL BUDGET ENVELOPE IMPLEMENTATION

Question 1	How do regulatory boards elsewhere implement and apply capital budget envelopes or similar mechanisms?

Section 3 examines strategies and practices employed by regulatory bodies across various jurisdictions implementing and applying capital budget envelopes or analogous mechanisms, explores mechanisms that govern capital investments, and assesses how they contribute to the broader context of utility operations and regulatory oversight.

Regulatory boards in other Canadian jurisdictions have a range of authority to make project specific capital investment decisions and/or to set overall capital investment budget limits. If a board does not explicitly approve or disapprove specific capital investments, it falls on the utility to manage and prioritize approved capital projects within the approved budget:

> *"As part of setting overall budgets, the [b]oard may explicitly direct certain projects to be completed and disallow specific projects from advancing, but to the extent that the [b]oard does not explicitly approve or disapprove projects, the utility should retain the management responsibility to re-prioritize, re-scope, or defer projects within the approved list of projects so that the overall approved budget is respected and the targeted reliability improvements and risk mitigations is achieved."* [9,10]

3.1 Jurisdictional Overview

Table 3 summarizes the capital budget envelope mechanisms implemented in the jurisdictions reviewed by Midgard:

Table 3: Jurisdictional Overview of Capital Budget Mechanisms

Canadian Jurisdiction	Capital Budget Mechanisms
British Columbia	• BC Hydro – COS: forecast capital expenditures and historical actual capital additions to rate base are approved as part of a COS Revenue Requirement Application. • FortisBC – PBR: rates are set following a PBR framework, where cost of service is used to set the first-year base capital budget and Operation and Maintenance ("O&M") requirements, after which a PBR formula is applied

[9] Midgard, P0360-D016-RPT-R03-EXT, NLPUB Capital Budget Application Guideline Review, 2020-Oct-29, Section 8.1.2, p. 62.

[10] This original quote references the Board, but the statement as used in this quote is intended to be generalized.

Canadian Jurisdiction	Capital Budget Mechanisms
	mechanistically to establish budget envelopes for the remainder of the test period. • No annual Capital Budget Applications.
Manitoba	• COS: The Manitoba Public Utilities Board ("MPUB") does not approve or disapprove capital projects, rather the MPUB approves rates based upon a proposed capital investment plan. The regulated utility subsequently decides which capital projects it will execute in consideration of the approved rates. • No annual Capital Budget Applications.
Ontario	• PBR: For both transmission & distribution utilities, rates are determined within a PBR framework, where the initial-year base capital budget and O&M needs are established using a COS model. Subsequently, a PBR formula is mechanistically applied to define the capital and operating budget limits for the remaining test period. ○ Utilities may apply for explicit approval of additional capital spending needs that arise between re-basing filings using the Incremental Capital Module ("ICM"), Advanced Capital Module ("ACM") or Z-factor[11] processes. ○ Leave to Construct ("LTC") is a standalone capital approval process for transmission projects that are required to satisfy a Standard Issues List developed by the OEB.[12] • There are no annual Capital Budget Applications.
Nova Scotia	• Line-By-Line Capital Approvals: All individual projects and routines exceeding $1M must be reviewed and approved by the Nova Scotia Utility and Review Board ("NSUARB"). • Annual Capital Budget Applications.

As shown in Table 3, capital budget approval mechanisms differ across provinces ranging from line-by-line capital approvals to rate setting only, wherein the utility choses which capital investments it will execute. However, in all reviewed cases, capital budget mechanisms are underpinned by a notional, or forecast, set of

[11] Z-factor costs go into a deferral account for adjudication at the next re-basing period.

[12] OEB, Filing Requirements For Electricity Transmission Rate Applications, Chapter 4 – Leave to Construct and Related Matters under Part VI of the Ontario Energy Board Act, Section 4.1, p. 4. Link.

planned capital projects – the mechanisms for controlling capital budgets once those forecasts are evaluated by the board[13] vary by jurisdiction. The range of control mechanisms are represented by the following:

1) Line by Line Capital Approvals: A review and approval process is required for individual projects or routines exceeding a certain cost threshold. This approval process is facilitated through the submission of annual Capital Budget Applications. This is the process followed in Newfoundland and Labrador and Nova Scotia.
2) Cost of Service ("COS"): To authorize capital expenditures, a COS Revenue Requirement Application[14] is employed. COS involves justifying and evaluating capital projects within the context of building an overall revenue requirement for the utility. COS is a common approach in utility regulation for determining capital and O&M requirements. One of the strengths of COS is that it limits the requirements for special mechanisms to address irregular capital investment projects that can cause significant fluctuations in revenue requirement from year to year. For example, a generation utility typically has fewer but larger ("lumpy") capital investments when compared to a distribution utility that typically has a larger number of smaller capital investments. This is because a generation utility has comparatively few high-dollar value generators and generating stations compared to a distribution utility that has a much larger number of lower dollar value assets such as poles, transformers and breakers. Once a revenue requirement is approved it is expected that the utility will manage its capital budgets and O&M costs within the approved revenue requirement, with planned activities being adapted as required to avoid exceeding the approved revenue requirement. Utility management may adapt when individual capital projects exceed their initially planned budgets, or when unexpected incremental investment needs arise between COS applications, by deferring or re-scoping other capital projects to stay within the revenue requirement bounds that were used to establish rates.
3) Performance Based Regulation ("PBR"): The PBR model is also commonly used for setting capital and O&M budgets. Rates are established within a PBR framework using a two-step process. In step one, rates are initially set within the context of a COS type approach to determine the base capital and O&M budgets in the initial year of the test period. In subsequent years of the test period, a deterministic PBR formula is mechanistically applied to set annual rates, which then define implicit or explicit budget limits for capital and O&M spending. Actual implementations vary in practice, with some annual PBR updates tending to be more administrative activities performed by the board (or board staff) without significant intervener inputs (e.g., in Ontario), while others involve filings with limited intervener inputs on select issues (e.g., in British Columbia for FortisBC). Regardless of the

[13] Not necessarily approved by, but at least observed and evaluated by the relevant regulatory board to support the evidentiary basis of decision.

[14] The exact label may differ across jurisdictions, but the basic contents are substantively similar.

PBR implementation details, there is an inherent assumption that both capital and O&M budget requirements change gradually and predictably over time, and that the utility will become more efficient over time. In jurisdictions using PBR regulation, it is typically associated with distribution utilities due to their larger number of smaller projects. However, PBR can also work effectively for larger transmission utilities, except where major transmission expansion projects occur and incremental capital expenditure authorizations are required. However, similar to COS, utility management may also adapt projects to address financial constraints by deferring or re-scoping capital projects to stay within the approved revenue requirement when other capital projects exceed their initially planned budgets or unexpected project needs arise.[15]

4) Rate Setting: Some regulators (i.e., Manitoba) do not explicitly approve or disapprove individual capital projects, but rather set rates on the basis of a proposed capital plan and O&M forecast. Once rates are set, the utility then has the management responsibility to adapt its capital plan and O&M expenditures as it deems appropriate in consideration of the approved rates. The responsibility for capital project prioritization remains solely with the utility as it seeks to ensure adequate system reliability and manage its risk profiles as new priorities emerge or cost overruns in other areas of the organization place financial constraints on the utility's budgets considering the approved rates.

3.2 Conclusions

A range of regulatory approval processes exist across Canadian jurisdictions for regulatory boards to evaluate and either explicitly or implicitly approve capital budgets. Regulatory practice ranges from boards explicitly approving each capital project that exceeds a specified cost threshold to utility management being responsible for adapting capital plans to fit within approved rates. Thus, while the concept of capital budget envelopes is utilized in various jurisdictions, the capital budget envelope implementational details vary:

> *"Utility capital spending approvals take different forms in the different Canadian jurisdictions. Regulators in some jurisdictions do not have the mandate to explicitly approve capital spending but are able to implicitly provide direction on capital budgets by approving rates that support a specified range of capital spending. Regulatory Boards in other jurisdictions have the mandate to explicitly approve or disapprove capital spending, but depending upon the jurisdiction, that mandate may be exercised upon aggregate or categorized capital spending envelopes, individual projects (in some cases only those that exceed a specified cost threshold), or a combination of these approaches."* [16]

[15] Regulatory bodies like the OEB provide flexibility through incremental spending applications, allowing utilities to address emergent needs. Moreover, during annual reviews, FortisBC evaluates and records the actual capital costs for significant projects and requests accommodations for variances.

[16] Midgard, P0360-D016-RPT-R03-EXT, NLPUB Capital Budget Application Guideline Review, 2020-Oct-29, Section 3, p. 18.

Three (3) of the four (4) regulatory approaches used across Canada explicitly have some form of capital budget envelope (COS, PBR, Rate Setting), with the difference being the degree of management authority to adapt its capital plans within the financial constraints applied by the board (i.e., either through a revenue requirement or rates). For line-by-line capital approvals, there is nothing inherent in that approach that precludes considering a capital budget envelope.

In those cases where boards do not approve individual projects but instead provide a form of budget envelope constraint with differing degrees of expected adherence to the underlying planned capital budget, utility management has a parallel authority and responsibility to adapt capital plans in response to emergent events in consideration of the financial constraints imposed by the board (i.e., either through rates or revenue requirement).

4 PRIORITIZING REFURBISHMENT/REPLACEMENT ASSETS IN CAPITAL EXPENDITURES

Question 2	How do regulatory boards elsewhere ensure that the assets proposed for refurbishment/replacement are appropriately prioritized and included in the CAPEX investment list?

Section 4 examines how other Canadian regulatory boards ensure that the assets proposed for refurbishment/replacement are appropriately prioritized and included in the applicable Capital Plan. Due to asymmetrical information and resources, a utility always possesses more detailed and comprehensive information about its operations, plans, and proposed capital investments than do the regulatory board and intervening parties. This asymmetrical information imbalance leads to challenges in making informed regulatory decisions, as the party with more information may have an advantage in presenting its case or influencing regulatory outcomes:

> *"To function effectively and ensure the necessary tension between interests, a capital budget approval process requires the applicant to provide complete and accurate supporting information for the planned investments. It is important to recognize that even if the application is full, complete and accurate, a significant informational asymmetry always exists between the applicant (i.e., utility) and the intervenors and regulatory Board."* [17]

Countering information asymmetry is necessary to support regulatory boards so they are able to make well-considered decisions:

> *"If the process is transparent and equitable, intervenors will have sufficient information to challenge the applicant about any remaining areas of disagreement, and develop effective argument that will inform regulatory Board decisions. Well informed argument from both the applicant and intervenors should (at least theoretically) provide the necessary tension to enable the regulatory Board to make fair and considered decisions."* [18]

The establishment of a prioritized list of capital investments helps support fully informed regulatory board decisions. By presenting information that allows interveners and the board to form their own arguments about the ranking of proposed capital investments which can be compared against the utility's internal

[17] Midgard, P0360-D016-RPT-R03-EXT, NLPUB Capital Budget Application Guideline Review, 2020-Oct-29, Section 3, p. 18.

[18] Midgard, P0360-D016-RPT-R03-EXT, NLPUB Capital Budget Application Guideline Review, 2020-Oct-29, Section 3, p. 18.

justifications and evaluations used to form its proposed capital plan, the asymmetric informational gap between utilities, interveners, and regulatory boards may be bridged.

4.1 Jurisdictional Review

Table 4 summarizes capital investment prioritization strategies in the Canadian jurisdictions reviewed by Midgard.

Table 4: Jurisdictional Overview of Capital Investment Prioritization Strategies

Prioritization Strategy	Description	Example Jurisdiction
Subjective Prioritization	• Involves justifying capital projects primarily based on expert judgement without a robust quantitative evaluation and/or ranking. • Supports a diverse range of capital investment decisions but lacks objective comparison between potential investments. • Holistic expert judgement evaluation is based on qualitative aspects and subjective arguments within the context of what the utility believes ratepayers should find acceptable.	Small (typically Municipal) Ontario distribution utilities
Prioritizing based on asset health[19]	• Assesses asset health and justifies asset replacements primarily on the basis of asset health alone. • Prioritizes assets with asset health ratings below a certain threshold (e.g., poor or very poor) to maintain system reliability. • Typically, does not adjust asset health thresholds to account for differences in the risks posed to a system by different assets (i.e., is susceptible to “it is old, therefore we must replace it” type arguments).	**Ontario** EB-2022-0013: Alectra Utilities Corporation (“Alectra”) ICM Appendix C.5
Prioritizing based on risk	• Prioritizes assets based on associated asset risks, considering a predetermined set of risks, which typically include financial, system reliability, safety, environmental and utility reputational risks.	**British Columbia** BC Hydro 2023 to 2025 Revenue Requirement Application – Appendices I, J & K

[19] Independent of risk and value models.

Prioritization Strategy	Description	Example Jurisdiction
	• Addresses assets nearing the end of their service lives due to concerns related to asset risk, considering both asset condition (i.e., probability of failure) and consequence of failure. • Requires risk assessments for proposed investments so that arguments can move beyond those based solely on asset health (probability of failure) to now consider the risk (probability & consequence of asset failure) in capital plans.	Appendix A.3 **Ontario** ENWIN Utilities Ltd. 2020 Distribution Rate Application [20] Appendix C.6
Prioritization based on a value model	• Quantifies project effectiveness in reducing risk and achieving other objectives per unit of investment. These additional objectives may include optimal lifecycle costs (e.g., capital and O&M cost tradeoffs), other corporate objectives. • Attempts to ensure capital investments are optimized to achieve a desired trade-off between system reliability, cost and risks.	**British Columbia** FortisBC 2020 to 2024 Multi-Year Rate Plan ("MRP") – Asset Investment Planning ("AIP") process Appendix A.2.1 **Manitoba** Manitoba Hydro 2023/24 & 2024/25 General Rate Application[21] Appendix B.2

All utilities reviewed have some form of prioritization strategy that they present as evidence in their respective regulatory filings. These prioritization strategies typically result from explicit filing requirements and/or board decisions that define what is acceptable practice.[22] As illustrated in Table 4, practices range from predominantly subjective prioritization based on expert judgement to prioritization based on value

[20] While there are other issues with ENWIN's capital planning that hinder its ability to fully implement prioritization based on a value model, ENWIN has made efforts to establish rankings based on the reduction of risk per dollar spent. This places ENWIN in a transitional phase between prioritizing based on risk and prioritizing based on risk per dollar spent, which is moving toward a value model-based approach.

[21] In practice, Manitoba Hydro is not currently achieving its desired objective of capital prioritization. However, it is actively working toward this goal.

[22] Board decisions either explicitly define what is acceptable by board order or tacitly through overall acceptance of filings over time that become the accepted filing requirements for a utility.

models. As utilities mature their asset management capabilities, they are able to progress along the prioritization strategy scale from subjective and/or asset health-based prioritization strategies towards risk and value-based prioritization strategies. It is worth noting that none of the utilities reviewed by Midgard has fully implemented a value model prioritization yet. Utilities like Manitoba Hydro and BC Hydro are gradually moving in that direction as their asset management capabilities mature, but they are not at that level yet:

1) Manitoba Hydro is in the early stages of implementing prioritization based on a value framework model. It is not currently achieving that objective in practice but has updated plans to become competent in the future.
2) BC Hydro currently provides its regulator with a risk-based project data without providing a prioritized list because BC Hydro has an internal value-based framework that it uses for internal capital project prioritization.

As such, the most common practices among major utilities in Canada generally involve asset health and risk-based approaches to project prioritization. According to the NLPUB Guidelines, Newfoundland and Labrador utilities are required to provide risk-based evaluations of their capital investments.[23]

In practice, utilities typically do not exclusively rely on a single prioritization strategy, as identified in Table 4. Instead, they tend to employ a predominant strategy that aligns with their current level of asset management maturity, while also striving to implement superior strategies that would be supported once they reach a higher level of asset management maturity. Accordingly, utilities typically utilize a range of prioritization strategies, often employing multiple strategies for different asset types or asset groupings. Different functional groups within a utility may be at different levels of asset management maturity, and as such have different abilities to support more or less advanced prioritization approaches. For example, in a recent filing by Manitoba Hydro, Midgard and Manitoba Hydro's expert asset management consultant both evaluated the transmission and generation groups as being more mature than the distribution group. Accordingly, distribution group justifications tended towards asset health justifications whereas transmission and generation group justifications tended towards risk and/or attempts at broader value-based justifications.

4.2 Conclusions

Utilities have more detailed capital portfolio, need and risk information than do regulatory boards and interveners, which creates informational asymmetries between regulatory participants. To support effective intervention and enable robust board decisions, prioritized lists of capital investments with clear quantifiable

[23] NLPUB, Capital Budget Application Guidelines (Provisional), Section III, Table: "Required Information", p. 16-17. Link.

justifications are necessary to bridge this asymmetrical information gap (i.e., subjective justifications inhibit bridging the informational asymmetry gap).

Regulatory boards ensure assets proposed for refurbishment/replacement are appropriately prioritized through a combination codified filing requirements (e.g., BC Hydro's Capital Filing Guidelines,[24] Manitoba's Minimum Filing Requirements ("MFR"),[25] and Ontario's Chapter 5 Filing Requirements[26]) and refinement through board orders and direction. The ability of a utility to provide advanced prioritization information is limited by the utility's asset management maturity. For example, in Ontario, smaller distribution utilities are allowed to provide primarily subjective prioritizations despite Chapter 5 Filing Requirements (as written) that require a high level of asset management maturity and prioritization information.[27] As a utility's asset management maturity increases, the implementation of formal asset condition assessment and monitoring programs, risk asset programs, and/or value-based decision-making increases the prioritization information available from utilities:

> *"…adopting formal asset condition monitoring and asset management practices helps utilities optimally pace capital spending to maintain expected service levels and to manage corporate, safety and environmental risks. If properly implemented, formal asset management and risk management practices also enable production of quantified defensible evidence showing that the utility's proposed capital spending is necessary and prudent."* [28]

As a result, the ability of a regulatory board to ensure that proposed investments to refurbish or replace assets are appropriately prioritized in a utility's CAPEX investment portfolio is constrained by the utility's prevailing level of asset management maturity. Higher levels of asset management maturity are required to support improved utility investment prioritization decisions, and to provide regulators and interveners with objective asset condition and risk information to help address the information asymmetry gap.

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[24] See Appendix A.1 for details.

[25] See Appendix B.1 for details.

[26] OEB, Filing Requirements For Electricity Distribution Rate Applications, Chapter 5 – Consolidated Distribution System Plan. Link.

[27] See Appendix C.4 for details.

[28] Midgard, P0360-D016-RPT-R03-EXT, NLPUB Capital Budget Application Guideline Review, 2020-Oct-29, Section 7.4, p. 54.

5 ENSURING EFFECTIVE CAPITAL INVESTMENT OUTCOMES

Question 3	How do regulatory boards elsewhere ensure that CAPEX investments yield the anticipated outcomes, (e.g., customer service and enhanced reliability and reduced operating and maintenance costs) and how are utility management practices employed to measure and quantify enhancements in customer service and reliability stemming from capital projects?

Section 5 examines the strategies employed by regulatory boards in other jurisdictions to ensure the realization of expected outcomes from CAPEX investments including sustaining or improving system reliability[29] and reducing lifecycle costs.[30]

As is required in Newfoundland and Labrador, classifying investments by the primary objectives they are intended to achieve enables boards, utilities, and interveners to compare historical and forecast spending trends in each category with the outcome trends that the capital investment is intended to achieve:

> *"Investment Classification helps address stakeholder concerns about effective regulatory participation and intervention, by enabling intervenors to evaluate and challenge the need for and effectiveness of overall spending in each investment category, without requiring a time and resource-consuming deep dive into each individual project or program activity, thereby mitigating "can't see the forest for the trees" type issues."* [31]

There are several key components necessary to ensure that these classified capital investments yield the anticipated outcomes:

1) Categorizing Outcomes: defining the anticipated outcome;
2) Forecasting Outcomes: forecasting the expected benefit for each anticipated outcome;
3) Measuring Actual Outcomes: measuring the actual benefit received after the capital is invested; and
4) Comparing Forecast vs. Measured Outcomes: comparing the forecasted benefit to the actual measured benefit.

In North America, typical utility asset management practices are currently below the maturity level required to achieve all four (4) of these steps. However, boards are increasingly requiring utilities to improve their

[29] Customer service and enhanced reliability.

[30] The question asked by the CA focused primarily on O&M costs, but lifecycle costs include both capital cost and O&M costs.

[31] Midgard, P0360-D016-RPT-R03-EXT, NLPUB Capital Budget Application Guideline Review, 2020-Oct-29, Section 7.1, p. 51.

asset management practices over time. Currently, the majority of utilities only support Categorizing Outcomes, with utilities either subjectively[32] or quantitatively[33] describing expected Forecast Outcomes. The NLPUB Guidelines are a typical example, with each utility's capital budget applications categorizing expected outcomes for its projects and programs.[34,35]

Examples of categorizations and measurements of forecasted outcomes seen across Canada are displayed within the Newfoundland and Labrador classification framework in Table 5.

Table 5: NLPUB Projects and Programs and Investment Classification[36,37]

Investment Classification	Description	Example	Example Outcome Measurement
Mandatory	Investments prescribed by a governing body, such as the provincial or federal government and the Board.	Removing all Polychlorinated Biphenyls ("PCB") in transformer oil by a set date	1) Compliance (e.g., binary yes/no answer) 2) Cost-Effectiveness (e.g., unit cost of removing PCBs from transformers).
Access	Investments, including asset relocations, that a utility is obligated to undertake to provide a customer (either a load or generation customer) or a group of customers with access to electricity services and modify the utility's electrical system.	Residential, Commercial and Industrial Interconnections	1) Percentage of Interconnections completed within specified timeframes 2) Cost Effectiveness (e.g., unit cost per interconnection)

[32] Qualitative claims of expected improvements in system reliability and/or resilience without a quantified estimate of the improvement that would support a quantitative comparison between options.

[33] For example, ENWIN Utilities Ltd. ("ENWIN") provided a prioritized list of ENWIN's capital investment projects, which is discussed further in Appendix C.5.

[34] NLPUB, Capital Budget Application Guidelines (Provisional), Section II(B), p. 12-13. Link.

[35]Projects: individual capital investments, typically of a non-repetitive nature, which are justified and budgeted separately from capital programs; and Programs - capital investments comprised of a number of asset-related activities that are high volume, repetitive, like-for-like capital replacements, enhancements, or additions that are expected to continue into the foreseeable future.

[36] NLPUB, Capital Budget Application Guidelines (Provisional), Section II(A), Table: "Investment Classification", p. 10-12. Link.

[37] Ibid, Section II(B), Table: "Projects and Programs and Investment Classification, p. 13.

Investment Classification	Description	Example	Example Outcome Measurement
Renewal	Investments that involve replacing and/or refurbishing system assets to extend their service lives, thus ensuring the continued ability to provide customers with their expected electricity services.	Maintaining targeted asset health demographics and/or asset risk profile (e.g., Pole Replacement Program)	1) Cost Effectiveness (e.g., unit cost per pole replacement) 2) Target asset demographics, asset health demographics, and/or risk profile[38]
System Growth	Investments aimed at modifying a utility's system to align with projected changes in customer electricity resource demands.	Generation and transmission projects stemming from a utility resource plan or distribution projects increasing load density in urban/suburban areas.	1) Execution Effectiveness (e.g., comparison between initial budget and final cost) 2) Planned versus completed projects (e.g., % of planned projects completed within the planned schedule)
Service Enhancement	Investments directed at altering a utility's system to enhance system operations to be more efficient, effective and/or reliable.	Reliability and/or resiliency projects such as remotely operated sectionalizing switches or automatic reclosers	1) Reliability improvement per dollar spent[39] 2) Execution Effectiveness (e.g., comparison between initial budget and final cost) 3) Planned versus completed projects (e.g., % of planned projects completed within the planned schedule)
General Plant	Investments in a utility's non-electric system assets, i.e., excluding generation, transmission, or	IT infrastructure investments to improve operations activities	1) Overall utility cost-effectiveness (e.g., dollars per customer, utility head count per customer)

[38] Target risk profile is generally not seen across Canada due to limited asset management maturity or a lack of reporting requirements, but BC Hydro has reported this metric for select assets (i.e., dam safety risk profile). More typical is an objective to replace identified poor or very poor condition assets within a specified time horizon.

[39] This metric is not currently reported by any of the Canadian utilities reviewed by Midgard.

Investment Classification	Description	Example	Example Outcome Measurement
	distribution system assets. These assets comprise land and buildings, tools and equipment, rolling stock, as well as electronic devices and software employed to support daily business and operational activities.		2) Call centre response (seconds to pick up, number of calls dropped)

For further examples of target metrics, please refer to the following appendices:

- British Columbia: Appendix A.4;
- Manitoba: Appendix B.3; and
- Ontario: Appendix C.6.

In the context of the components necessary to ensure that classified capital investments yield anticipated outcomes, Table 6 illustrates the extent to which strategies employed by regulatory boards have advanced in ensuring the realization of expected outcomes from CAPEX investments in the reviewed jurisdictions.

Table 6: Jurisdictional Overview – Components for Ensuring Expected Outcomes in Classified Capital Investments

Component	British Columbia	Manitoba	Ontario	Nova Scotia
Categorizing Outcomes	✓	✓	✓	✓
Forecasting Outcomes	✓	✓	✓	
Measuring Actual Outcomes			✓[40]	
Comparing Forecast vs. Measured Outcomes				

In many of the reviewed regulatory applications, objectives (e.g., cost savings, reliability improvements) are often used to justify capital investments. However, establishing a clear correlation between these stated

[40] In Ontario, ENWIN's PROSORT project prioritization tool is considered an exception and most utilities do not currently attempt to measure actual outcomes.

objectives, the categories they fall into, and measurable metrics attributable to individual investments or investment categories is typically absent. While there are overarching assessments to determine whether utilities are meeting global reliability performance targets (e.g., global SAIDI and SAIFI), these assessments are conducted at a holistic level rather than providing a more granular validation of the effectiveness of individual investments. As a result, boards are typically unable to ensure that individual CAPEX investments yield the anticipated or promised outcomes, because a feedback loop that would enable validation of utility claims is absent at a sufficiently granular level.

5.1 Conclusions

Categorizing investments by their objectives simplifies regulatory oversight and intervention. However, asset management practices in North America are currently evolving, with many utilities only addressing the initial step of categorization and the establishment of various target metrics, while some are beginning to explore outcome forecasting.

As a result, regulatory jurisdictions across Canada often lack a structured approach to guarantee that individual capital investments or investment portfolios result in the expected outcomes. Attempts to ensure anticipated outcomes from capital investments vary across jurisdictions and are primarily conducted at a holistic level, examining high-level metrics such as SAIDI and SAIFI, as well as scorecard metrics like dollars per distribution line length or dollars per customer served.

Additionally, although utilities may be reluctant to forecast reliability improvements associated with specific investments, some utilities do use metrics like risk reduction or reliability enhancement per dollar spent to assess and include projections of enhanced reliability in their capital investment proposals. However, most utilities choose not to provide any quantified forecasts.

In summary, boards are typically unable to ensure that CAPEX investments yield the anticipated outcomes because utility management practices do not quantitatively forecast these anticipated outcomes or measure them at a sufficiently granular level. Current practice typically involves evaluating utility outcomes at the holistic generation, transmission, and distribution levels and assessing CAPEX investments prospectively (i.e., based on the claims at the time of investment) without any meaningful feedback loop to verify if the CAPEX investments actually achieve the claimed outcomes.

6 QUANTIFYING COST SAVINGS IN OPERATIONAL MAINTENANCE

Question 4	How are utility management practices used to quantify improvements in cost savings in operational and maintenance costs resulting from a capital project?

Section 6 examines the economic analyses performed by utilities to quantify operations and maintenance cost savings resulting from a capital project. In short, the operations and maintenance cost savings resulting from a capital project are typically evaluated using a cost benefit analysis based upon an underlying Net Present Value ("NPV") calculation of the costs and benefits of an investment.

Depending on the investment categorization (see Section 4), whether it constitutes a project or program, as well as the significance threshold, Newfoundland and Labrador capital budget applications are required to provide the following cost benefit analysis information:

> *"Projects and programs shall be evaluated using a cost benefit analysis that has the following features:*
>
> 1) *Cost: Full Life Cycle Cost Evaluation (i.e., fully capitalized development, construction, operations & maintenance, fuel, capital upgrades, decommissioning/abandonment) including all direct costs and indirect costs (e.g., finance charges such as AFUDC and overhead allocations)*
> 2) *Benefits: Benefits beyond baseline benefits associated with status quo (e.g., load served, ratepayer benefits, reliability benefits, energy efficiency benefits, cost savings, etc.)*
> 3) *NPV: All calculations shall be made on an NPV basis with clearly defined assumptions and inputs.*
> 4) *Basis of Comparison: The basis for comparing alternatives on a cost benefit basis shall be consistent with industry practice (e.g., base load generation uses Levelized Cost of Energy, peaking generation uses Levelized Cost of Capacity or equivalent metrics).*
> 5) *Risk - Safety / Environment: If non-monetary cost/benefits are used in the cost benefit comparison, an equivalency shall be established between monetary and non-monetary cost/benefits."* [41]

The cost-benefit analysis requirements in other jurisdictions are, in principle, substantively similar to the requirements in Newfoundland and Labrador, with the following caveats:

[41] NLPUB, Capital Budget Application Guidelines (Provisional), Section III, Table: "Required Information", p. 16. Link.

1) Presentation Form: the presentation of cost-benefit analysis materials differs widely across jurisdictions depending on the style of the presenter. Since the differences are primarily stylistic rather than substantive, this distinction will not receive further discussion.
2) Comparative Analysis: cost-benefit analyses are typically used to compare two (2) alternatives or justify a standalone investment without a presented alternative. In cases where the analysis is comparative, typical approaches require comparing NPV values or the NPV of the differences in costs (e.g., O&M and capital) and benefits. In standalone cases, the NPV should be positive.
3) Analysis Term: utilities such as BC Hydro are permitted to select and justify an analysis term (typically measured in years). As a result, some utilities may choose terms that do not match the expected lifespan of the underlying investment (a concern when the options being compared have different lifespans). However, in practice, Midgard has observed that most utilities tend to consider and account for differences in asset lifespans when performing their analysis.
4) Discount Rate: since the selection of the discount rate has a significant impact on the calculated benefits over time (e.g., O&M cost savings) versus the upfront costs (e.g., initial capital costs) due to its influence on the time value of money, selecting the appropriate discount rate is essential for a fair evaluation. Therefore, it is important that the discount rate be expressed in either real or nominal terms, depending on whether the inputs are expressed in real or nominal values. For example, the time value of energy should always be expressed in real terms because inflation does not change the inherent value of a GWh of energy, but costs can be expressed in either nominal or real terms to match the selected discount rate. The consistent application of the discount rate is particularly important when determining the basis of comparison, such as Levelized Cost of Energy or Levelized Cost of Capacity.
5) Non-Monetary Costs/Benefits: instead of analyzing non-monetary benefits within a cost-benefit framework, utilities such as BC Hydro, Manitoba Hydro, and others use a structured decision-making approach to compare alternatives that contain non-monetary benefits. This means that financial costs/benefits (e.g., O&M and capital) may not be compared to non-monetary benefits on a basis that aligns with the risk frameworks of most utilities.
6) Continued Maintenance and Capital Investment: utilities have a range of policies regarding continued maintenance and incremental capital investments in assets that are reaching the end of their expected lives. Specifically, some utilities will continue to make capital investments in assets that remain in service beyond their calculated expected service lives, while others will not (e.g., Hydro One), as part of the cost-benefit calculation. The practice of ceasing incremental capital investments in assets beyond their expected service lives will also reduce the benefits derived from O&M savings in a cost-benefit analysis.
7) Payback Periods: Nova Scotia requirements indicate that a "payback period" is to be considered when evaluating the costs and benefits associated with items such as O&M cost savings. Using

payback period as a standalone evaluation is not recommended because it ignores the time value of money, but use of payback periods may be instructive when used as a supplement to a NPV analysis.

6.1 Conclusions

A cost-benefit analysis is the key tool used by most utilities in Canada to quantify and evaluate O&M cost savings resulting from a capital project. As such, cost-benefit analysis plays a pivotal role in justifying capital projects that are expected to produce financial benefits. Project justifications typically rely on cost-benefit analysis when evaluating project alternatives or justifying the project based on the financial benefits it is expected to deliver (e.g., O&M cost savings). Although the form and details within cost-benefit analyses vary from jurisdiction to jurisdiction, they generally align with the requirements outlined for Newfoundland and Labrador, including the use of NPV calculations.

7 ASSESSING RISK FOR CAPITAL PROJECT DECISIONS

Question 5	How are utility management practices used to quantify the risk of not proceeding with a capital project?

Section 7 examines the utility management practices used to assess the potential risks associated with not proceeding with a capital project. Risk is the product of probability of an event occurring and the expected consequence when that event occurs. For utility assets the probability of asset failure increases as the asset's condition degrades and the asset approaches the end of its life, but the expected consequences of that expected failure event remains the same (absent system configuration changes). The expected consequences of a failure event may include a variety of consequences including system reliability, financial, safety, environmental, and utility reputational impacts.

Newfoundland and Labrador capital budget funding applications are required to provide certain information pertaining to risk assessment. Specifically, NLPUB's Guidelines state:

> *"Projects and programs shall be evaluated for risk mitigation in the following categories:*
>
> 1) *Reliability*
> 2) *Safety*
> 3) *Environment*
>
> *Risk mitigation shall be calculated as the difference in risk before and after the proposed alternatives were implemented.*
>
> *The calculation of risk shall conform to an internationally recognized standard for calculating risk.*
>
> *The evaluation shall be supported by a documented risk management program that clearly demonstrates how risk is evaluated and equivalency given to the different risk elements (i.e., how risk-based prioritization functions), and how risk reduction is calculated."* [42]

Various elements of risk are also considered in the following contexts:

- Project Alternatives – opting to defer a project while preserving the existing state aims to mitigate potential risks associated with postponement, considering the impact on reliability, safety, human resources, and other concurrent capital projects;[43]

[42] NLPUB, Capital Budget Application Guidelines (Provisional), Section III, Table: "Required Information", p. 16-17. Link.

[43] Ibid, p. 15.

- Asset Stranding Risk – risk of the capital addition becoming stranded before reaching its intended useful lifespan;[44] and
- Prioritization – projects and programs for Renewal, Service Enhancement, and General Plant, organized based on the effectiveness of risk reduction per dollar invested.[45]

7.1 Jurisdictional Review

Table 7 summarizes risk assessment considerations in the Canadian jurisdictions reviewed by Midgard.

Table 7: Jurisdictional Overview of Risk Assessments

Canadian Jurisdiction	Risk Considerations	Risk Analysis Frameworks
British Columbia	BC Hydro: Reliability, Safety, Environmental , Reputational, Financial Losses. FortisBC: Financial, Reliability, Environmental, Health & Safety, Regulatory, Corporate Reputation, And Customer Service	• BC Hydro: 2023 to 2025 Revenue Requirement Application – Appendices I, J & K (Appendix A.2.1) • FortisBC: 2020 to 2024 Multi-Year Rate Plan (“MRP”) – Asset Investment Planning (“AIP”) process (Appendix A.2.1)
Manitoba	Drought, interest rates, ageing assets, export prices, disruptive technology, regulatory changes, cybersecurity, innovation, succession planning, self-generation, stranded assets, talent management.	• Enterprise Risk Management (“ERM”): program being established to provide an enterprise-wide assessment of risks faced by the utility.[46] • Asset Risk Management Framework: considers asset removal, developing asset health indices, assessing climate change risks on assets, and establishing methods for evaluating and managing risks. Target completion date = October 2025.[47]
Ontario	Safety, Financial, Reliability, Sustainability	• Chapter 5 Filing Requirements state that a distributor should provide asset information

[44] Ibid, p. 16.

[45] Ibid, Section IV, p. 17.

[46] Manitoba Hydro, 2023/24 & 2024/25 General Rate Application, Tab 2, Sectio 2.7. Link.

[47] Manitoba Hydro, 2023/24 & 2024/25 General Rate Application, Tab 7, Figure 7.10, #4, p. 20-21. Link.

Canadian Jurisdiction	Risk Considerations	Risk Analysis Frameworks
		(e.g., asset risks) and demonstrate consideration of the potential risks of proceeding/not proceeding with individual capital expenditures.[48] • Hydro One Networks Inc. ("HONI"): Reliability Risk Model, considers asset-specific hazard curves and asset demographics (Appendix C.7). • Prioritization: project are ranked within the Consequence tiers identified in a Risk Matrix.[49]
Nova Scotia	Health & Safety, Environmental, Business Sustainability.	• Prioritization: Generation, Transmission, Distribution, and Information Technology capital project are ranked within the Consequence tiers identified in a Risk Matrix.[50]

Quantifying the risk associated with not proceeding with a capital project is functionally equivalent to comparing the risk of leaving the capital asset in service versus the alternative of fully replacing the capital asset and bringing it to a "new" condition.[51] In cases where partial replacement alternatives exist (e.g., stubbing a distribution pole, polymer injection for buried cables to extend their insulation lives, replacing bushings on an older transformer, etc.), the asset is not necessarily brought to a "new" condition but rather to a condition that is sufficiently improved in a cost-effective manner to reduce the probability of failure within an acceptable range, considering the reduced investment cost. As such, Midgard observes that utilities typically quantify the comparative risks of leaving the asset in service against the assumed alternative of fully replacing the asset, but often ignore partial risk mitigation alternatives. BC Hydro recently provided evidence that it takes this approach:

> *"As discussed above, the current methodology of assessing risk scores reflects the risk of deferring investment; therefore, by definition, the post-capital investment risk score of the investments in Appendix I and J [of the revenue requirement application] would be zero as these are the investments which have been included in the capital plan and which have capital expenditures or additions in the*

[48] OEB, Filing Requirements For Electricity Distribution Rate Applications, Chapter 5 – Consolidated Distribution System Plan, Section 5.3 p. 9-11. Link.

[49] OEB, EB-2019-0032, Exhibit 2, Section 5.4.3.2, Attachment 2-A, Table 74, p. 213. Link.

[50] NSPI, M11017, 2023 ACE Plan, Exhibit N-1, Appendix F, p. 81-82, Link.

[51] This typically includes like-for-like asset replacement but may include other alternatives that replace the asset with another capital investment that provides similar or greater functionality than a like-for-like replacement (e.g., upgrades, system reconfigurations, etc.).

Test Period. That is, the pre-capital investment risk will only materialize if BC Hydro were to defer the investment and such a deferral is not planned. If BC Hydro proceeds as planned, the risk will have been mitigated and the post-capital investment risk score in Appendix I [of the revenue requirement application] will be zero." [52]

While Midgard does not accept the argument that the post-capital investment risk score is zero because the "new" asset still poses a risk associated with its potential failure (i.e., the probability of failure of even a "new" asset is non-zero), utilities typically ignore this fact and treat the investment as fully mitigating the risk of deferring investment. Presumably, this is because the utility deems the residual risk after replacement as being sufficiently low that it can be ignored in the overall risk reduction calculation.

Consequently, utilities typically prioritize projects based on the risks of not proceeding with a proposed capital project, assuming that a project that fully mitigates the risk provides the best value to ratepayers. However, the decision to act is different from deciding which alternative action is the most cost-effective for ratepayers (i.e., lowest cost to achieve an acceptable residual risk). By assuming that returning to a "new" state is always the preferred default alternative, utilities may be missing lower-cost alternatives that adequately mitigate risk. Utilities typically gauge the risks associated with the current state only (the "Before" scenario) and omit assessing the residual risks after implementing the investment project (the "After" scenario).

7.1.1 Project Alternatives – The "Do Nothing" Approach

Regulatory boards typically require applicants to provide information demonstrating the need for and scope of capital projects for which they seek approval. Mandatory filing information often includes examination of alternatives to the proposed capital investment.[53] Applicants must demonstrate a project's necessity, feasibility, and supporting assumptions, including cost, benefit, and risk comparisons of alternatives.

When evaluating the risks being addressed by proposed projects, the "Do Nothing" option is commonly used as a reference point, but utilities tend to omit assessment of residual post-project risks and treat any deferral option as an extended or permanent deferral. Many utilities have capital planning optimization frameworks (e.g., a proprietary tool in the case of BC Hydro, or Copperleaf C55 in the case of Manitoba Hydro) that assist in the capital planning process. However, although these tools may allow the user to evaluate a range of deferral options, the presentation of an explicit short-term "Deferral" option is typically missing in the applications made to regulatory boards. Utilities appear to avoid providing information on the cost savings and additional ratepayer risk associated with temporary investment deferrals, instead focusing on the need

[52] BC Hydro, BC Hydro Compliance with Directive 20 and 87 of G-91-23, Section 3.1, p. 41, l. 9-16. Link.

[53] Refer to Appendix A.5 for an example.

to invest, assuming that the cost-effective approach always involves full risk extinguishment (i.e., post-investment risk is effectively reduced to zero).

However, when evaluating potential alternatives, pre- and post-investment risk assessment is important in the context of delivering value to ratepayers. Mitigating the vast majority or even a significant proportion of risk using a low-cost alternative may from a ratepayer perspective be preferable to a more expensive option that notionally mitigates "all" risk, because risks are brought down to an acceptable level for the lowest cost.

7.2 Conclusions

Risk is defined as the product of the probability and consequences of asset failure. As asset condition degrades and assets approach the end of their lives, the probability of expected failure increases, but the consequence of expected failure remains the same (ceteris paribus).

Utilities typically quantify the risks of leaving an asset in service against the assumed alternative of fully replacing the asset and often ignore lower cost partial risk mitigation alternatives. Consequently, utilities typically prioritize projects based on the risks of not proceeding with a capital project, and also assume that only a project that fully mitigates the risk will provide adequate ratepayer value . However, the decision to act is different from deciding which alternative action delivers the best value for ratepayers. By assuming that returning to a "new" state is always the preferred default alternative, utilities may be missing lower-cost alternatives that adequately mitigate risk.

In summary, utilities typically gauge the risks associated with the current state only (the "Before" scenario) and omit assessing the residual risks after implementing the investment project (the "After" scenario).

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8 SAIDI/SAIFI IN ANNUAL CAPEX ANALYSIS

Question 6	What role does SAIDI/SAIFI play in the regulator's analysis of the annual CAPEX budget, and when are SAIDI/SAIFI objectives expected to be realized or accomplished?

Section 8 examines the role System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") metrics have within the context of the regulator's analysis of the annual CAPEX budget, and explores expectations associated with when SAIDI/SAIFI objectives are to be achieved.

SAIDI/SAIFI metrics are commonly accepted measures of system reliability in all Canadian regulatory jurisdictions. As a result, utilities are able to benchmark themselves against their utility peers using a common standard of measurement:

> *"The practice of requiring utilities to report on their standardized reliability performance trends is common to most Canadian jurisdictions, with some jurisdictions also requiring or suggesting that utilities benchmark their reliability performance against comparable peers, particularly when the utility is proposing increased renewal spending. Most jurisdictions ask utilities to report their performance trends including and excluding external factors beyond the utility's control, such as third-party supply interruptions and major meteorological event days, and in cases where external factors aren't excluded, it is a typical RFI to have reliability reported in this manner…"* [54]

SAIDI/SAIFI metrics can be reported both with and without major events that are outside a utility's control, such as third-party supply interruptions (e.g., loss of upstream generation or transmission from another utility that is supplying a distribution utility) and major weather-related events (e.g., ice storms, hurricanes etc.).

In their capital planning applications, utilities typically introduce SAIDI/SAIFI metrics to demonstrate system reliability trends and to frame the need for capital investments to maintain or improve SAIDI/SAIFI metrics. In the Newfoundland and Labrador context, NLPUB's Guidelines state:

> *"Historic and forecast system reliability trend information, including:*
>
> 1. *System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") graphs and tables for the overall electrical system as a whole and any relevant sub-segments (e.g., individually or collectively as a grouping):*

[54] Midgard, P0360-D016-RPT-R03-EXT, NLPUB Capital Budget Application Guideline Review, 2020-Oct-29, Section 7.2, p. 52.

a. *Historical: Past 10 years with and without Externally Caused Outages3, and with and without Major Events.*
b. *Forecast or Target: Next 5 years without Externally Caused Outages and without Major Events.*
c. *Benchmarking against similar utilities.*

2. *A list of the 10 worst performing feeders including relevant outage statistics compared to utility averages (e.g., SAIDI, SAIFI) for the past 10 years with and without major events, even if there is no proposed capital expenditures for these feeders. Where there are proposed capital expenditures related to one of these feeders, the information should address the particular issues."* [footnotes omitted][55]

8.1 SAIDI & SAIFI Definitions

In the electricity industry, utilities and regulators evaluate system performance using metrics such as those outlined in the IEEE Standard 1366-2012, "Guide for Electric Power Distribution Reliability Indices". SAIDI and SAIFI are among the most commonly used metrics to assess distribution and transmission system performance as defined in Table 8.

Table 8: SAIDI & SAIFI Definitions[56]

Metric	Description	Formula
SAIDI	The system average interruption duration for customers served per year.	Total Customer-Hours of Interruptions divided by Total Customers Served.[57]
SAIFI	The average number of interruptions per customer served per year.	Total Customer-Interruptions divided by Total Customers Served.[58]

8.2 Jurisdictional Review

Table 9 summarizes distribution and transmission reliability indices for the different Canadian jurisdictions reviewed by Midgard.

[55] NLPUB, Capital Budget Application Guidelines (Provisional), Section I(B), p. 9. Link.

[56] Electricity Canada, *Transmission & Distribution Indicators*. Link.

[57] Total customers served represents the number of end customers the utility is delivering electricity to.

[58] Ibid.

Table 9: Jurisdictional Overview of Distribution and Transmission Reliability Indices

Canadian Jurisdiction	SAIDI/SAIFI Metrics Considered	Comparators
British Columbia (Appendix A.6)	SAIDI, T-SAIDI, SAIFI, T-SAIFI-MI, T-SAIFI-SI, CAIDI, %ASAI, CEMI-4, MAIFI, DPUI, SARI	• Current year performance • Historical trends
Manitoba (Appendix B.4)	SAIDI, T-SAIDI, SAIFI, T-SAIFI	• Current year performance • Benchmarked against other utilities • Historical trends
Ontario (Appendix C.9)	All interruptions, all interruptions excluding loss of supply, all interruptions excluding major events and loss of supply for SAIDI and SAIFI. For historical data spanning the previous five years, number of interruptions that occurred as a result of the cause of interruption, number of customer interruptions that occurred as a result of the cause of interruption, number of customer-hours of interruptions that occurred as a result of the cause of interruption	• Current year performance • Benchmarked against other utilities • Regulator-defined performance targets • Historical trends (five years)
Nova Scotia (Appendix E.2)	SAIDI, SAIFI, CAIDI	• Current year performance • Benchmarked against other utilities • Historical trends

Although numerous system reliability metrics in addition to SAIDI/SAIFI are shown in Table 9 above (e.g., T-SAIDI, T-SAIFI, CAIDI), most these metrics are actually derivatives of SAIDI and SAIFI. For example, CAIDI is SAIDI divided by SAIFI, T-SAIDI is SAIDI for transmission only (i.e., NLH's SAIDI metric), T-SAIFI is SAIFI for transmission only (i.e., NLH's SAIFI metric).

Distribution and transmission reliability indices are used regularly in regulatory proceedings in all Canadian jurisdictions. Specifically, Midgard observes that SAIDI/SAIFI metrics are utilized in regulatory reviews of annual CAPEX budget in the following ways:

1) Reliability Metrics: SAIDI and SAIFI, among other reliability indices, are key metrics considered by regulators to assess the performance of distribution and transmission systems. These metrics provide data for evaluating the reliability of utility systems.
2) Current Performance: Regulators analyze reliability metrics for the most recently available year of record to gauge the real-time performance of utility systems. This assessment helps in understanding the current reliability status and identifying areas that might require CAPEX investments to achieve targeted reliability levels.
3) Benchmarking: Utility systems often compare their reliability metrics against their utility peers in addition to tracking their own historical performance trends. Benchmarking provides insights into areas of needed change and helps utilities determine which of their peers are performing well and may have practices worthy of emulation.
4) Regulator-Defined Targets: Some regulators such as the Ontario Energy Board, and the BCUC (for FortisBC), specify performance targets related to reliability metrics like SAIDI/SAIFI. Utilities are expected to meet these targets, and achieving or failing to achieve the targets can impact approved rates under PBR regimes.
5) Utility Defined Objectives: In cases where the regulator has not defined SAIDI/SAIFI targets, utilities may propose their own objectives in terms of SAIDI/SAIFI targets and use these objectives to help justify capital investments. Regulators are therefore asked either explicitly or implicitly to determine if the proposed SAIDI/SAIFI objectives are reasonable.
6) Investment Effectiveness: Similar to the discussion on quantifying the O&M cost savings associated with capital investments, utilities typically do not currently validate that capital investments justified on the basis of improving or maintaining system reliability actually achieve that objective after they are commissioned.

8.3 SAIDI/SAIFI Timing

Achieving SAIDI/SAIFI objectives, after excluding major events outside the utility's control, is a continuous ongoing goal for utilities. In cases where the regulator does not set specific targets, utilities attempt to maximize system reliability within the constraints approved by regulators (e.g., within approved budgets in a COS regime or budget envelopes in a PBR regime). In cases where reliability targets are set by the regulator (e.g., as part of a PBR regime), minimum and target metrics are typically established and expected to be met, and the utility must decide which capital investments and O&M expenditures will be most effective in enabling it to achieve those reliability targets.

8.4 Conclusions

SAIDI/SAIFI metrics are a standard basis for utilities to measure and report system reliability performance. Reporting reliability trends, benchmarking against peer utilities, and setting system reliability objectives are common practices across most Canadian jurisdictions and often form the basis for capital and O&M spending justifications in regulatory applications.

Regulators assess SAIDI/SAIFI metrics either explicitly or tacitly as part of their decisions to approve capital and O&M budgets in consideration of the evidence provided by the utility and interveners. Regulators regularly weigh evidence about appropriate SAIDI/SAIFI targets or objectives, and that discussion is often shaped by jurisdiction-specific factors such as specific customer group needs and expectations (e.g., industrial customers' expectations differ from residential customers' expectations). While this conversation is often less quantified within COS and rate-setting models, system reliability remains a consideration for regulators when weighing application evidence.

Achieving SAIDI/SAIFI objectives (after excluding major events outside the utility’s control) is a continuous goal for utilities. In cases where the regulator does not set specific targets, utilities attempt to maximize system reliability within the constraints approved by their regulators (e.g., within approved capital budgets in a COS regime or budget envelopes in a PBR regime). In cases where reliability performance targets are set by the regulator (e.g., as part of a PBR regime), the utility must decide which capital investments and O&M expenditures are best able to achieve those target metrics.

APPENDIX A: BRITISH COLUMBIA OVERVIEW

Table 10 provides an overview of the British Columbia Regulator and prominent utilities considered in this report.

Table 10: British Columbia Public Utilities Board Overview

Category	Description	Hyperlink
Regulator	British Columbia Utilities Commission ("BCUC")	Link
Areas of Oversight	Electric Utilities (Crown and Investor Owned), Thermal Energy Utilities, Domestic Gas Utilities (Natural Gas, Propane), Gas Marketers, Basic Automobile Insurance, Intra-provincial pipelines	Link
Electric Utilities	BC Hydro – Generation, Transmission & Distribution (Crown-owned)	Link
	FortisBC – Generation, Transmission & Distribution[59] (Investor-owned)	Link

Table 11 summarizes applicable statutes and legislation of British Columbia that govern the BCUC and electric utilities.

Table 11: British Columbia – Statues & Legislation

Statute & Legislation	Hyperlink
BCUC	
Overview	Link
Utilities Commission Act	Link
Administrative Tribunals Act	Link
Clean Energy Act	Link
Freedom of Information and Protection of Privacy Act	Link
Fuel Price Transparency Act (Gasoline And Diesel)	Link
Insurance Corporation Act and Protection of Privacy Act	Link
BC Hydro	
BC Hydro and Power Authority Act	Link
BC Hydro Public Power Legacy and Heritage Contract Act	Link

[59] FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC).

Table 12 summarizes applicable rules, procedures and guidelines, for the BCUC.

Table 12: British Columbia – Rules, Procedures and Guidelines

Rules, Procedures and Guidelines	Hyperlink
BCUC	
Overview	Link
Rules of Practice and Procedure (includes Participant Cost Award rules)[60]	Link
Timing and Guidelines for the Filing of Information	Link
Certificate of Public Convenience and Necessity Guidelines	Link
Resource Planning Guidelines	Link
Mandatory Reliability Standards	Link
Negotiated Settlement Process Guidelines	Link
Streamlined Review Process	Link
Utility System Extension Test Guidelines	Link
Regulatory Account Filing Checklist	Link
Energy Supply Rules - Electric	Link
Participant Assistance/Cost Award Guidelines ("PACA")[61]	Link
Retail Markets Downstream of the Utility Meter Guidelines	Link
Decision and Order No. G-313-19 – Review of the Regulatory Oversight of Capital Expenditures and Projects	Link
BC Hydro	
2018 Capital Filing Guidelines (Attachment 1 in the referenced document)	Link
First Nations Information Filing Guidelines	Link
FortisBC	
Decision and Order No. G-120-15 - Multi-Year Performance Based Ratemaking Plans for 2014 through 2019 Approved by Decisions and Orders G-138-14 and G-139-14	Link

Table 13 summarizes applications to the BCUC considered in this report.

Table 13: Example BCUC Applications Considered

Proceeding	Hyperlink
BC Hydro	

[60] Participant Cost Award rules (Part VI) are applicable to proceedings that started after June 30, 2022. For cost award applications in proceedings that started before June 30, 2022, please see the Participant Assistance/Cost Award Guidelines.

[61] Applicable to proceedings started before June 30, 2022.

Proceeding	Hyperlink
Fiscal 2023 to Fiscal 2025 Revenue Requirements Application	Link
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application	Link
Fiscal 2017 to Fiscal 2019 Revenue Requirements Application	Link
Fiscal 2015 to Fiscal 2016 Revenue Requirements Application	Link
FortisBC	
FortisBC Inc. 2024 Annual Review of Rates	Link
FortisBC Inc. 2023 Annual Review of Rates	Link
FortisBC Inc. 2022 Annual Review of Rates	Link
FortisBC Inc. Annual Review for 2020 and 2021 Rates	Link
FortisBC Utilities Multi-Year Rate Plan Application for 2020 to 2024	Link

A.1 BC Hydro Capital Filing Guidelines

The 2018 Capital Filing Guidelines assist BC Hydro in preparing and submitting applications regarding capital expenditures, such as Revenue Requirement Applications, Utilities Commission Act ("UCA") Section 46(1) and 44.2 applications, and compliance reporting. They serve as a reference for reviewing BC Hydro's capital spending across various application and reporting contexts.

Table 14 summarizes revenue requirement application guidelines and requirements for capital expenditures.

Table 14: BC Hydro Capital Filing Guidelines – Revenue Requirement Applications[62]

Category	Capital Filing Guidelines
Review Scope for Capital Projects	• Projects with a CPCN, expenditure schedule, or exemption, with capital expenditures in the test period, may be reviewed for execution details. • Projects subject to a future CPCN or Section 44.2 application, with capital expenditures in the test period, may be reviewed for need and alternatives. • Projects without a CPCN or Section 44.2 application requirements may be reviewed for need, alternatives, and forecast reasonableness.
Filing Requirements for Individual Capital Projects Above Materiality Limits	• Include project details, forecasts, CPCN status, extensions, and links to strategies/studies. • Describe project objectives, scope, schedule, risks, mitigation, and cost estimates.

[62] BC Hydro, Review of the Regulatory Oversight of Capital Expenditures and Project Compliance with BCUC Order No. G-313-19 Directive 2, Attachment 1, para. 3-10, p. 1-3. Link.

Category	Capital Filing Guidelines
	• Address capital investment category, risk, value, public interest, construction start, and final costs.
Additional Information Relevant to Capital Expenditures	• Include justifications and alternatives for major projects above specified limits. • Provide information on Implementation Phase risks, impacts, and benefits. • Review recurring Capital Programs and ensure the inclusion of “Technology” projects exceeding $10 million in capital project summaries. • Report any significant changes in capital management processes and identify deficiencies as needed.

It is important to note that there may be situations where deviations from these guidelines are necessary, and the BCUC retains the flexibility to adapt its approach. BC Hydro also has the option to propose modifications to these guidelines.

A.2 FortisBC Multi-year Rate Plan Components

Rates for FortisBC Energy Inc. (“FEI”) and FortisBC Inc. (“FBC”) (collectively, “FortisBC”) are currently set using a MRP beginning in 2020 and ending in 2024. The MRP for 2020 to 2024 includes an index-based approach, a forecast approach to capital expenditures, earnings sharing, an efficiency carry-over mechanism, service quality indicators, a financial off-ramp, an annual review process, flow-through treatment, and updated supporting studies for rate setting. The following MRP elements were approved by the BCUC:

> ***“MRP Plan Components***
>
> - ***MRP Term:*** *A five-year MRP term starting in 2020 and ending in 2024.*
> - ***Index-based Approach:*** *Use of a formula or index‐based approach to FEI and FBC’s controllable O&M and FEI Growth capital, incorporating the MRP formula components outlined below.*
> - ***Forecast Approach to Capital:*** *Use of a forecast approach for FEI Sustainment capital and FBC Regular capital. Specifically, the Panel approves the level of forecast capital to be incorporated in rates for the three‐year period 2020‐2022 in these categories as set out in the Application. FortisBC is directed to file an updated forecast of the 2023 to 2024 capital expenditures for BCUC approval in the Annual Review for 2023 rates.*

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- ***Earnings Sharing Mechanism:*** *A 50 percent sharing between customers and the Utilities of FEI and FBC's achieved ROE above or below the allowed ROE.*
- ***Efficiency Carry Over Mechanism:*** *The Utilities may apply for approval of an efficiency carry over mechanism at any time in the last three years of the MRP term, either in advance or following the action/initiative giving rise to savings being undertaken. If approved, the net savings identified will be shared equally between ratepayers and the Utilities for a maximum period of three years following the end of the MRP term. The efficiency carry over mechanism proposed by FortisBC is denied. The Panel finds that the proposal does not adequately balance the interests of ratepayers and the Utilities.*
- ***Service Quality Indicators:*** *Nine service quality indicators for FEI and eight service quality indicators for FBC with certain updated benchmarks, thresholds and annual basis of calculations as outlined in the Decision. In addition, there are four informational indicators in the Decision for FEI and FBC, respectively, which the Utilities must report on with the service quality indicators in the Annual Review.*
- ***Financial Off-ramp:*** *A plan off-ramp will be triggered if earnings in any one year vary from the allowed ROE by more than +/- 150 basis points (post sharing).*
- ***Annual Review Process and MRP Assessment:*** *An Annual Review process with certain topics which must be addressed is outlined in the Decision. In addition, the Panel finds that having an assessment of the MRPs would be useful in determining the approach to ratemaking following the end of the MRP term.*
- ***Flow-through treatment:*** *Specific revenue requirement items approved for flow-through and deferral account treatment of certain items are as outlined in the Decision.*
- ***Supporting Studies:*** *Use of updated supporting studies for setting rates, including updated depreciation rates, working capital, shared and corporate allocations, and capitalized overheads rates."* [63]

Table 15 summarizes the formula components of the MRP.

Table 15: FortisBC MRP Formula Components[64]

Component	Description
Growth Factor	A growth factor multiplier for O&M is set at 75 percent with an increase in the multiplier for FEI Growth capital from 50 percent to 100 percent. Additionally, the Panel approves the use of forecast average number of customers and

[63] BCUC, Decision and Order No. G-165-20 and G-166-20, p. ii. Link.

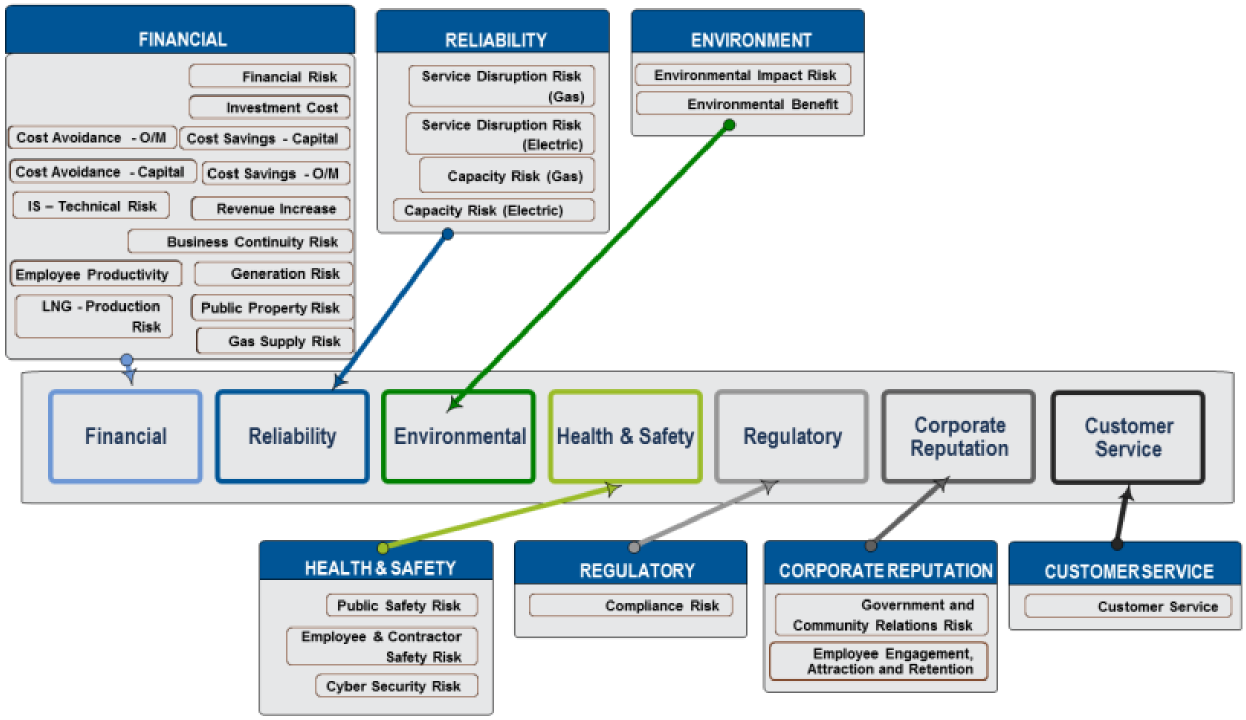
[64] BCUC, Decision and Order No. G-165-20 and G-166-20, p. ii-iii. Link.

Component	Description
	forecast Gross Customer Additions for controllable O&M and FEI Growth capital, respectively, with true-up mechanism to reflect actual amounts.
Inflation-Factor	An inflation factor based on Statistics Canada BC-CPI and the BC-AWE indexes, where the labour to non-labour ratio is to be set annually based on actual for the most recently completed year.
X-Factor	An X-Factor of 0.5 percent, inclusive of a stretch factor.
Base O&M	A Base O&M per customer amount for the index-based approach to controllable O&M sing 2018 Actual O&M as the starting point, and subject to the Panel's determinations on FortisBC's proposed adjustments as outlined in the Decision.
Base FEI Growth Capital	A Base Unit Cost for the index-based approach to FEI's Growth capital using an average of the 2016-2018 Actual unit costs, and subject to the Panel's determinations on FortisBC's proposed adjustments as outlined in the Decision.

A.2.1 FortisBC Asset Investment Planning Value Framework

FortisBC has initiated an Asset Investment Planning ("AIP") process aimed at enhancing decision-making transparency and consistency across its asset classes. In the first phase of implementation in 2017, FortisBC installed Copperleaf C55 software and developed processes to quantify benefits and mitigate risks for Gas Sustainment projects. The second phase is ongoing, encompassing Electric Sustainment, Information Systems, Fleet, and Facilities. The AIP tool employs a value framework with seven core values, derived from FortisBC's strategic objectives and values: financial, reliability, environmental, health & safety, regulatory, corporate reputation, and customer service, each with associated measures. Figure 1 illustrates an overview of the AIP process.

Figure 1: FortisBC Asset Investment Planning Value Framework Overview



A.3 BC Hydro Project Prioritization Information

In its revenue requirements applications, BC Hydro provides information to assist in capital investment project prioritization, including an overview of significant capital projects, starting with a high-level summary of planned expenditures, and delving into project specifics, including detailed descriptions, drivers, and risk assessments. Additionally, it includes supporting documentation in the form of summaries of broader strategies and studies, which offer context and rationale for the listed projects.

- Capital Investment Information for Significant Projects – capital investment information is presented for projects that exceed $2M for Technology projects and $5M for other types of projects, including risk and value scores for individual projects.
- Capital Project Descriptions – in-depth descriptions of capital projects and programs is presented, including information about projects and programs with planned total capital expenditures of $10M or more for Technology projects and $20M or more for other projects. It encompasses detailed project descriptions, key drivers, issues addressed by the projects, discussions of project alternatives, implementation risks, and risk treatment strategies.
- Strategies, Plans, and Studies – various documents related to strategies, plans, and studies are provided. These documents are designed to explore potential solutions for upgrading the Power System and associated infrastructure, but not necessarily make financial commitments. They

investigate and recommend broader regional, system, or business solutions or policies, all of which support the justification for future projects or solutions.

This information is tabulated in each iteration of BC Hydro's Revenue Requirement Applications, in the appendices.[65]

On April 21, 2023, the BCUC issued Decision and Order G-91-23 which directed BC Hydro how best to implement RCIA's recommendations for incorporating both pre-capital investment risk scores and post-capital investment risk scores into Appendices I & J of its revenue requirement applications:[66]

"Accordingly, RCIA proposes updating the implementation of the Guidelines, and suggests the following "evolutionary enhancements" be provided by BC Hydro as part of its next RRA:

…

1) *Enhanced Risk Reporting*
    a. *Appendix I: Replace the current pre-capital investment Risk Score (Column AC) showing the single highest uncategorized risk with columns of the highest pre-capital investment risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability).*
    b. *Appendix I: Add columns for the post-capital investment risk scores for the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability). This allows the evaluation of different alternatives based on risk mitigation per investment dollar spent.*
    c. *Appendix J: Replace the currently unquantified pre-capital investment Key Drivers (which are just consequence categories), with the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability). This allows evaluation of the relative criticality of the different pre-investment Key Drivers across the portfolio of investments.*
    d. *Appendix J: Add to Key Drivers, the post-capital investment risk scores for the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability). This allows evaluation of different alternatives based on the risk they mitigate per investment dollar spent so that ratepayers can evaluate the benefits they will receive from the proposed investment."* [67]

[65] Example: BC Hydro, Fiscal 2023 to 2025 Revenue Requirements Application, Appendix I, J & K. Link.

[66] BCUC Decision and Order G-91-23, Directive 20, p. 315. Link.

[67] Ibid, p. 96. Link.

A.4 BC Hydro Performance Metrics

In its latest Revenue Requirements Application, BC Hydro presented new performance metrics to monitor effectiveness, especially in areas with increased investment for reliability and strategic initiatives. These metrics aim to quantify resource use, efficiency, outputs, and customer benefits, aligning with feedback from discussions with stakeholders. An example of these performance metrics for its reliability investments is presented in Table 16.

Table 16: BC Hydro Performance Metrics For Reliability Investments[68]

	Area of Investment	Incremental Investment Previous Application and Current Test Period ($ million)	Desired Outcome	Supporting Metric	Target	Chapter 5 Reference
Reliability Investments	Mandatory Reliability Standards	F2022 Decision $21.7 F2023 to F2025 Plan $3.0	Increased compliance and system resilience and reliability	MRS Reported Non-Compliance Reduction Against F2021 (%)	F2023 –60% F2024 –70% F2025 –80%	Section 5.7
				Mitigation Plan Actions Completed on Time (%)	F2023 – 96% F2024 – 97% F2025 – 98%	
	Vegetation Management	F2022 Decision $25.0 F2023 to F2025 Plan $16.7	Increase system reliability by decreasing vegetation originated outages	Distribution Forced Outages – Vegetation Originated (%)	F2023 – 37% F2024 – 35% F2025 – 30%	Section 5.8
				Transmission Right of Way Maintained (%)	F2023 – 20% F2024 – 20% F2025 – 20%	
	Cybersecurity	F2022 Decision $3.0 F2023 to F2025 Plan $6.5	Increase system resilience and reliability	BitSight Security Rating (Basic / Intermediate / Advanced)	F2023 – Advanced F2024 – Advanced F2025 – Advanced	Section 5.9
				BitSight Security Ranking Amongst Canadian Peers	F2023 – Upper Quartile F2024 – Upper Quartile F2025 – Upper Quartile	

I the same Application, BC Hydro also provides a list of performance metrics for the following categories:[69]

- Safety Metrics;
- Financial Metrics;
- Compliance Metrics;
- People Metrics;
- Operational / Service Delivery Metrics;
- Capital Delivery Management Metrics;

[68] BC Hydro, Fiscal 2023 to 2025 Revenue Requirements Application, Section 5.6, Table 5-12. Link.

[69] BC Hydro, Fiscal 2023 to 2025 Revenue Requirements Application, Appendix E. Link.

- Customer Interconnections Metrics;
- Load Forecast Accuracy Metrics; and
- Vegetation Management Metrics.

A.5 Certificates of Public Convenience and Necessity

In British Columbia, for public utilities and other parties wishing to construct or operate utility facilities, the BCUC requires utilities to file a Certificate of Public Convenience and Necessity ("CPCN") so the review of these applications by the BCUC can proceed efficiently. The CPCN Guidelines:

> *"…provides general guidance regarding the Commission's expectations of the information that should be included in CPCN applications while providing the flexibility for an application to reflect the specific circumstances of the applicant, the size and nature of the project, and the issues raised by the application."* [70]

A specific element of CPCN Guidelines requires applicants to provide details pertaining to a capital project's need and justification, including an analysis of alternative capital investment strategies, specifically:[71]

- Identification of the project's necessity, feasibility, and assumptions, along with a list of considered alternatives, including reasons for dismissing some of them early in the process;
- A comprehensive comparison of costs, benefits, and risks for the project and each alternative, using cost estimates meeting specific accuracy standards;
- Calculations of the project's revenue requirements and their impact on customer rates;
- Net present value calculations for incremental costs and benefits, along with explanations for the chosen term and discount rate;
- An assessment of social and environmental factors, comparing the project to alternatives and evaluating overall impacts; and
- Information linking the project to the applicant's approved long-term resource plan, explaining how the plan supports and justifies the project's need.

A.5.1 Example BC Hydro CPCN Application – Mainwaring Substation Upgrade Project

Consider BC Hydro's approved CPCN for its Mainwaring Substation Upgrade Project, which required the replacement of two of its power transformers and 50/60 series feeder section with all associated equipment

[70] BCUC, Order G-20-15, Appendix A, p. 1. Link.

[71] Ibid, p. 4-5. Link.

at the Mainwaring distribution substation located in South Vancouver, British Columbia. BC Hydro initially identified seven alternatives for the project:

- Doing nothing (or ongoing sustainment of individual assets);
- Two transformer alternatives: refurbishing the T1 and T3 power transformers or replacing them; and
- Four 50/60 feeder section alternatives: three different combinations of refurbishing and/or replacing equipment in the 50/60 feeder section or replacing the 50/60 feeder section with a new substation.

BC Hydro reasoned that replacing the two power transformers was the only feasible project alternative, combined with three feasible 50/60 feeder section alternatives. This determination was made via a structured decision framework, considering that doing nothing was ruled out due to safety and environmental risks, refurbishing certain power transformers was deemed unfeasible due to the risk of critical component failures, and replacing a feeder section with a new substation was rejected because of higher costs and negative stakeholder impacts.[72]

A.6 BC Hydro Distribution and Transmission Reliability Indices

BC Hydro considers the following distribution and transmission reliability indices, summarized in Table 17 below. These indices collectively cover various themes related to the reliability and performance BC Hydro's transmission and distribution systems, including measures for the frequency and duration of interruptions, the availability of service, the impact on customers experiencing multiple outages, and the overall system performance in terms of reliability and restoration times.

Table 17: BC Hydro Distribution and Transmission Reliability Indices[73]

Index	Description
SAIDI	A measure of the amount of time, in hours, an average distribution customer is without power in a year.
T-SAIDI	A measure of the average total interruption duration, in hours that a delivery point experiences in a year.
SAIFI	A measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience in a year.
T-SAIFI-MI	A measure of transmission interruptions of less than one minute in duration that a delivery point experiences in a year.

[72] BC Hydro, Certificate of Public Convenience and Necessity for the Mainwaring Substation Upgrade Project Application, Section 3.1, p. 3-1, l. 6 to p. 3-2, l. 15. Link.

[73] BC Hydro Fiscal 2023 to 2025 Revenue Requirements Application, Appendix Q – Attachment 1, p. 1. Link.

Index	Description
T-SAIFI-SI	A measure of transmission interruptions of one minute or more that a delivery point experiences in a year.
CAIDI	A measure of the average interruption, in hours, per interrupted distribution customer in a year.
%ASAI	A measure of the percentage of time service is available in the year.
CEMI-4	Percentage of customers experiencing four or more outages in a year.
MAIFI	A measure of the frequency of momentary (less than one minute) interruptions per distribution customer served in a year.
DPUI	A measure of overall bulk electricity system performance in terms of a composite index of unreliability expressed in system minutes in a year. It considers all forced and planned outages except interruptions attributed to generators.
SARI	A measure of the average restoration time, in hours, for each transmission delivery point in a year.

BC Hydro's SAIDI and SAIFI targets are based on several factors, which include long-term historical reliability trends and current-year performance. These targets also consider the annual variability caused by weather. Moreover, BC Hydro ensures the comparability of its SAIDI and SAIFI metrics by accounting for storm impacts and excluding major events.

APPENDIX B: MANITOBA OVERVIEW

Table 18 provides an overview of Ontario Regulator and prominent utilities considered in this report.

Table 18: Manitoba Public Utilities Board Overview

Category	Description	Hyperlink
Regulator	Manitoba Public Utilities Board ("MPUB")	Link
Areas of Oversight	Electric utilities, Natural Gas Utilities, Propane, Water & Wastewater Utilities, Pipelines, Automobile Insurance, Government Cheque Cashing and payday loans, Energy Efficiency Utility	Link
Electric Utilities	Manitoba Hydro ("MH")	Link

Table 19 summarizes applicable statutes and legislation of Manitoba that govern the MPUB and electric utilities.

Table 19: Manitoba – Statues & Legislation

Statute & Legislation	Hyperlink
MPUB	
Overview	Link
The Public Utilities Board Act	Link
Bill 44 – The Public Utilities Ratepayer Protection And Regulatory Reform Act	Link
The Crown Corporations Governance and Accountability Act	Link
The Efficiency Manitoba Act	Link
The Financial Administration Act	Link
The Loans Act, 2020-2021	Link
The Environment Act	Link
Manitoba Hydro	
The Manitoba Hydro Act	Link

Table 20 summarizes applicable rules, procedures and guidelines, for the MPUB.

Table 20: Manitoba – Rules, Procedures and Guidelines

Rules, Procedures and Guidelines	Hyperlink
MPUB	

Rules, Procedures and Guidelines	Hyperlink
General – Rules, Forms and Policies	Link
Hearing Process	Link
MPUB – Rules Of Practice and Procedure	Link
Manitoba Hydro	
Manitoba Hydro – Electric Board Terms of Reference	Link

Table 21 summarizes applications to the MPUB considered in this report.

Table 21: Example MPUB Applications Considered

Utility	Proceeding	Hyperlink
Manitoba Hydro	2023/24 & 2024/25 General Rate Application	Link
Manitoba Hydro	2021/22 Interim Rate Application	Link
Manitoba Hydro	2019/20 Electric Rate Application	Link
Manitoba Hydro	2017/18 & 2018/19 General Rate Application	Link

B.1 Minimum Filing Requirements

The MPUB does not approve or disapprove capital projects, and there are no annual Capital Budget Applications. However, as a Minimum Filing Requirement ("MFR") for its General Rate Applications ("GRA"), Manitoba Hydro provides the following information regarding its capital expenditures:[74]

- MFR-87 – the most current Capital Expenditure Forecast. If no CEF exists, please provide the capital expenditure assumptions used for planning purposes.
- MFR-88 – for all completed capital projects in excess of $10 million since 2018, a table showing the actual project costs and final pre-construction budgets.
- MFR-89 – a variance analysis for various projects, comparing the final project costs with the budgets identified at the previous GRA and explaining the reasons for any material variances.
- MFR-90 – a summary of the condition of Manitoba Hydro's capital assets based on the utility's updated asset management methodology. Indicate areas of significant required investment and the planned prioritization of those investments.
- MFR-91 – A schedule detailing the breakdown of the balances by component of capitalized costs (wages, overhead etc.) in construction work in process, consistent with the last Annual Report, for each major Generation and Transmission project and Business Operations Capital.

[74] Manitoba Hydro, 2023/24 & 2024/25 General Rate Application, Tab 10, MFR-87-94, p. 8-9. Link.

- MFR-92 – A schedule that indicates the amount of cash flow from electric operations, forecast electric base capital spending, and net cash flow available to finance each Major Generation & Transmission Project in the past five years and in each of the 20 forecast years. Include the (electric) capital coverage ratio.
- MFR-93 – Manitoba Hydro's Major Capital Projects Quarterly Reports to the PUB since the previous GRA.
- MFR-94 – Details of capital projects/expenditures that have been cancelled, reprioritized, or deferred as a result of the implementation of the corporate asset management framework and corporate value framework for the last five fiscal years and the test years.

B.2 Corporate Value Framework

All capital projects, with the exception of customer service work, which is required by Manitoba Hydro to execute, are evaluated using a Corporate Value Framework ("CVF") which determines the net value of a given capital investment. The CVF indicates positive or negative value to a given capital investment through various categorizations and metrics:

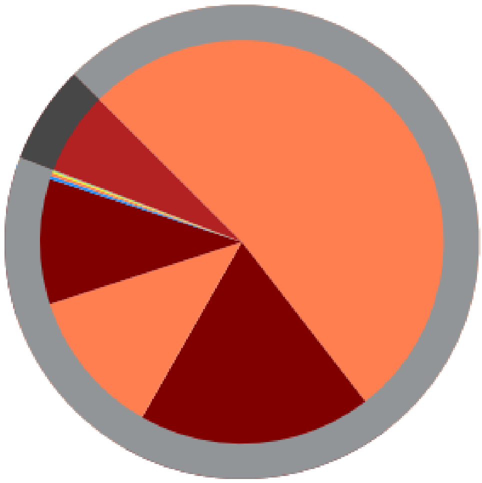
> *"The CVF consists of 5 categories (Financial, Environmental, Reliability, Corporate Citizenship, and Safety & Security) and 26 more granular "value measures", which may apply to an investment and indicate a positive or negative value in proceeding.*
>
> *Value measures are applied to potential investments to quantify the probability and consequence of the benefit or risks being mitigated. Valued investments are then compared against one another to determine optimal investment timeframes."* [75]

Figure 2 illustrates Manitoba Hydro's CVF for the Long Spruce Generator Protection Replacement Project, a diagram provided as a part of Manitoba Hydro's overall capital investment justification for the project.

[75] Manitoba Hydro, 2023/24 & 2024/25 General Rate Application, Tab 7, Section 7.4.1.3, p. 43, l. 8-13. Link.

Figure 2: Corporate Value Framework – Long Spruce Generator Protection Replacement Project[76]

CORPORATE VALUE FRAMEWORK



Value Measure	Value Points	% of Value
Lost Generation Risk	82,151	64.06%
Financial Risk	36,865	28.75%
Safety Risk	366	0.29%
O&M Financial Benefits	176	0.14%
Environmental Risk	110	0.09%
Total Cost	-8,577	6.69%
Total Value	**111,091**	
Value/$K	**12.95**	

B.3 Manitoba Hydro Asset Management Gap Assessment

In September 2016, Manitoba Hydro enlisted the services of UMS Group to carry out a Gap Assessment of its Asset Management capabilities. This assessment aimed to assess the organization's existing asset management capabilities and procedures and provide guidance for the implementation of an exemplary Asset Management System.

The assessment recommends establishing performance measures to encompass tracking progress in implementing Asset Management transformation initiatives and assessing Asset Management performance:

> *"Asset Management Transformation Initiative Metrics:*
>
> - *Number of tasks completed on schedule*
> - *Number of tasks completed on budget*
> - *Number of communications to employees on Asset Management*
> - *Number of asset life-cycle strategies completed*
>
> *Asset Management Performance Metrics:*
>
> - *Equipment outage rate (number of forced and fault outages as % of total asset class)*
> - *Equipment failure rate (number of major failures as % of total asset class)*
> - *Equipment maintenance spend rate (avg. $ of maintenance per asset - by asset class)*

[76] Manitoba Hydro, 2023/24 & 2024/25 General Rate Application, IR Round 1, Coalition MH-I-122a-m Attachment 1, p. 6 of 87. Link.

- *Downtime as a proportion of total operating time(%)*
- *Number of service interruption per month (by asset class)*
- *% of AHi distribution good or fair (trend)*
- *Unplanned capital expenditure/total capital expenditures*
- *Corrective Maintenance cost/ Preventive Maintenance cost (by asset class)*
- *Emergency maintenance cost/ Total maintenance cost (by asset class)*
- *Maintenance Backlog (cost of maintenance due/ average annual maintenance expenditure)*
- *Preventive Maintenance Compliance %*
- *Asset Sustainability Ratio (sustainment capital expenditure/ depreciation expense)*
- *Asset Consumption Ratio (current value of asset class/ current replacement cost of asset class)*
- *Percent of Assets with complete, correct demographic data in Asset Register*
- *Percent of Work Orders with correct failure codes entered by Field"* [77]

B.4 Manitoba Hydro Distribution and Transmission Reliability Indices

Manitoba Hydro considers SAIDI and SAIFI as primary reliability indices to measure performance in its distribution and transmission systems, summarized in Table 22 below. The Transmission System Average Interruption Duration Index ("T-SAIDI") and Transmission System Average Interruption Frequency Index ("T-SAIFI") are the primary metrics used to assess performance measuring the average duration and frequency, respectively, of interruptions on the transmission system.

Table 22: Manitoba Hydro Distribution and Transmission Reliability Indices[78]

Index	Description
SAIDI	A measure of the amount of time, in hours, an average distribution customer is without power in a year.
T-SAIDI	A measure of the average total interruption duration, in hours that a delivery point experiences in a year.
SAIFI	A measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience in a year.
T-SAIFI	A measure of transmission interruptions of less than one minute in duration that a delivery point experiences in a year.

[77] Manitoba Hydro, 2017/18 & 2018/19 General Rate Application, Appendix 5.1, p. 42. Link.

[78] Manitoba Hydro, 2023/24 & 2024/25 General Rate Application, Tab 7, Section 7.1.4, p. 10 & 15. Link.

For SAIDI and SAIFI indices, interruptions are assessed at the delivery point, where power is provided to a connected customer or the distribution system. These measures are benchmarked against those of other Canadian utilities, as established by Electricity Canada, and are also compared to Manitoba Hydro's own historical performance.

APPENDIX C: ONTARIO OVERVIEW

Table 23 provides an overview of Ontario Regulator and prominent utilities considered in this report.

Table 23: Ontario Energy Board Overview

Category	Description	Hyperlink
Regulator	Ontario Energy Board ("OEB")	Link
Areas of Oversight	• Electricity Sector (generators, transmitters, distribution utilities, wholesalers, retailers and unit sub-meter providers, the Independent Electricity System Operator, and the Smart Metering Entity) • Natural Gas Sector (natural gas marketers)	Link
Electric Utilities	Alectra Utilities Corporation	Link
	ENWIN Utilities Ltd.	Link
	Hydro One Networks Inc. (Transmission & Distribution)	Link

Table 24 summarizes the primary statutes and legislation of Ontario that govern the OEB and electric utilities.

Table 24: Ontario – Statutes and Legislation

Statute & Legislation	Hyperlink
General	Link
Ontario Energy Board Act	Link
Electricity Act	Link
Energy Consumer Protection Act	Link
Statutory Powers Procedure Act	Link

Table 25 summarizes applicable rules, procedures and guidelines, for the OEB.

Table 25: Ontario – Rules, Procedures and Guidelines

Rules, Procedures and Guidelines	Hyperlink
Electricity	
General - Link to Rules, Codes & Requirements	Link
Accounting Procedures for Electricity	Link
Prescribed Interest Rates for Accounts of Natural Gas and Electricity Distributors	Link

Rules, Procedures and Guidelines	Hyperlink
Directive for the Disclosure of Information to Consumers by Electricity Retailers - Supply Mix	Link
Mergers, Amalgamations, Acquisitions and Divestitures (“MAAD”)	Link
Distribution System Code (“DSC”)	Link
OESP Guideline for Electricity Distributors and Unit Sub-Meter Providers	Link
2006 Electricity Distribution Rate Handbook	Link
Retail Settlement Code (“RSC”)	Link
Electricity Distributor Recovery of Regulatory Assets	Link
Standard Supply Service Code (“SSSC”)	Link
Electricity Retailer Code of Conduct	Link
Transmission System Code (“TSC”)	Link
Filing Guidelines for Combined Service Area Amendment & Asset Transfer Applications	Link
Unit Sub-Metering Code	Link
2005 Distribution Rate Adjustment	Link
Affiliate Relationships Code for Electricity Distributors and Transmitters	Link
Deemed Conditions of Licence - Distribution System Plans	Link
Authorized Electronic Business Transaction (“EBT”) Standards	Link
Filing Requirements for Service Area Amendment Applications	Link
Filing Requirements for Transmission and Distribution Applications	Link
Conservation and Demand Management Guidelines for Electricity Distributors	Link
Filing Requirements for Transmission Project Development Plans	Link
OEB Rules of Practice and Procedure for Enforcement Proceedings	Link
Practice Direction on Confidential Filings	Link
Practice Direction on Settlement Conferences	Link
Practice Direction on Cost Awards	Link
Cost of Capital Parameter Updates	Link
Handbook for Utility Rate Applications (Electricity And Natural Gas)	Link
OEB Rules of Practice and Procedure	Link
Other	
Reporting and Record Keeping Requirements (“RRR”)	Link
Staff Bulletins and Guidance To Industry	Link
Forms And Templates: Energy Contracts And Certificates Of Compliance	Link
Compliance and Enforcement Processes	Link
Enforcement Proceedings	Link

Rules, Procedures and Guidelines	Hyperlink
Performance Assessment	Link
Prescribed Interest Rates	Link
Tools, Resources, and Links	Link
Performance Standards for Processing Applications	Link

Table 26 summarizes applications to the OEB considered in this report.

Table 26: Example OEB Applications Considered

Proceeding	Hyperlink
Alectra Utilities Corporation	
2023 Electricity Distribution Rates	Link
2022 Electricity Distribution Rates	Link
2021 Electricity Distribution Rates	Link
2020 Electricity Distribution Rates	Link
2019 Electricity Distribution Rates	Link
2018 Electricity Distribution Rates	Link
ENWIN Utilities Ltd.	
2023 Electricity Distribution Rates	Link
2022 Electricity Distribution Rates	Link
2021 Electricity Distribution Rates	Link
2020 Electricity Distribution Rates	Link
2019 Electricity Distribution Rates	Link
2018 Electricity Distribution Rates	Link
Hydro One Networks Inc. (Distribution and Transmission)	
2022 Electricity Distribution Rates	Link
2021 Electricity Distribution Rates	Link
2020 Electricity Distribution Rates	Link
2018 to 2022 Electricity Distribution Rates	Link
2020 to 2022 Electricity Transmission Rates	Link
2019 Electricity Transmission Rates	Link
2018 Electricity Transmission Rates	Link

C.1 Rate Adjustment Parameters

Distribution rates are set on a forward test-year cost of service basis and subsequently indexed by a price cap index formula which is used to adjust the distribution rates to reflect expected growth in the distributors' input prices (the inflation factor) less allowance for appropriate rates of productivity and efficiency gains (the X-factor).[79]

- Inflation Factor – the OEB adopted a two-factor industry-specific price index methodology. The inflation factor is based on two weighted price indicators (labour and non-labour) which provide an input price that reflects Ontario's electricity industry.
- X-Factor – the X-Factor comprises of a productivity factor and a stretch factor. The productivity component is intended to be the external benchmark which all distributors are expected to achieve. The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of the distributor at the outset of the IR plan. The productivity factors are updated every five years.
- Stretch Factor – distributors are assigned annually to one of five efficiency cohorts with stretch factor values ranging from 0% to 0.6% based on an econometric total cost benchmarking model developed by Pacific Economics Group for the Board. This model is updated annually and posted to the Performance Assessment webpage.[80] The assignments are revised annually to reflect changes in efficiencies in the sector. The most efficient distributors, based on the cost evaluation ranking, are assigned the lowest stretch factors.

C.2 Performance-based Regulation Rate Setting Options

The Ontario Energy OEB ("OEB") has employed Incentive Regulation ("IR"), including formula-based and cost-based rate-setting, since it began regulating the rates of electricity distributors in 2001. Under its current approach to IR, the OEB uses one-year forecasted cost and revenue information to determine a base revenue requirement and the "base" rates that are set to recover that revenue requirement. In subsequent years, those base rates are adjusted annually according to an OEB-approved formula that includes components for inflation and the OEB's expectations of efficiency and productivity gains. Under this method, distribution rates are set on a forward test-year Cost of Service ("COS") basis and subsequently indexed by a price cap index formula used to adjust the distribution rates to reflect the expected growth in the distributors' input prices (the Inflation Factor) less allowance for appropriate rates of productivity and efficiency gains (the X-

[79] EOB, OEB, EB-2010-0379, Section 2. Link.

[80] OEB, Performance assessment. Link.

Factor). The IR structure keeps the onus on the utility to prioritize, manage and execute necessary projects and O&M spending within the approved limits set in OEB rate decisions.

Going into PBR, distribution rates are set based on a COS review. Subsequently, rates are adjusted based on changes to the input price index and the productivity and stretch factors set by the OEB.[81] PBR decouples the price (the distribution rate) that a distributor charges for its service from its cost. This is deliberate and is designed to incent the behaviors that more closely resemble those of competitive, cost-minimizing, profit-maximizing companies. This approach provides the opportunity for distributors to earn, and potentially exceed, the allowed rate of return on equity. It is not necessary, nor would it be appropriate, for rate base to be recalibrated annually.

Currently, three alternative rate-setting methods are available to distributors in Ontario. Each distributor may select the rate-setting method that best meets its needs and circumstances and apply to the Board to have its rates set on that basis. This provides greater flexibility to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and may include "lumpy" investments, while others have capital needs that are expected to be comparatively stable over a prolonged period of time. Figure 3 provides an overview of the three rate-setting methods.

[81] Please refer to Appendix C.1.

Figure 3: Rate-Setting Overview - Elements of Three Methods[82]

	4th Generation IR	Custom IR	Annual IR Index
Setting of Rates			
"Going in" Rates	Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form	Price Cap Index	Custom Index	Price Cap Index
Coverage	Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism – Inflation	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
Annual Adjustment Mechanism – Productivity	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking	To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits	Productivity factor		
	Stretch factor	Case-by-case	Highest 4th Generation IR stretch factor
Term	5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module	On application	N/A	N/A
Treatment of Unforeseen Events	The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance	Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.		

C.2.1 4th Generation IR

The 4th Generation IR option consists of a COS rebasing followed by four years of Incentive Rate-setting Mechanism ("IRM") adjustments, set by a simple price cap index formula of inflation less X factor (i.e., I-X), where the X-factor is based on a combination of industry conditions (productivity component) and distributor-specific performance (stretch factor component). This option is most appropriate for distributors

[82] OEB, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, Section 2.2, Table 4, p. 13. Link.

that anticipate some incremental investment needs will arise during the 5-year plan term. This method is appropriate for most distributors.

- Annual Adjustment – the annual adjustment follows an OEB-approved formula that includes components for inflation and the OEB's expectations of efficiency and productivity gains. The components in the formula are approved by the OEB annually. The formula is a rate adjustment equal to the inflation factor minus the distributor's X-factor.

C.2.1.1 Example – Alectra Utilities Corporation

Alectra Utilities serves approximately 1,070,000 mostly residential and commercial electricity customers in its five rates zones that cover 17 communities including parts of the Greater Toronto Area and the Geather Golden Horseshoe.

Alectra Utilities Corporation's most recent application for rates and charges to be effective January 1, 2023, was submitted under annual adjustment under the 4th Generation Price Cap IR option. As noted above, the OEB follows a standardized and streamlined process for hearing IRM applications filed under Price Cap IR. In each adjustment year of a Price Cap IR term, the OEB prepares a Rate Generator Model that includes, as a placeholder, information from the distributor's past proceedings and annual reporting requirements. A distributor will then review, complete, and include the model with its application, and may update the model during the proceeding to make any necessary corrections or to incorporate new rate-setting parameters as they become available. Figure 4, taken from the Decision and Rate Order for the 2023 rates Application, depicts the variable that determine the annual rate adjustment.

Figure 4: Price Cap IR Adjustment Formula[83]

Components		Amount
Inflation factor[4]		3.70%
Less: X-factor	Productivity factor[5]	0.00%
	Stretch factor (0.00% to 0.60%)[6]	0.30%

Inserting these components into the formula of Inflation Factor less X-Factor results in an increase of 3.40%[84] to Alectra's rates for 2023.

[83] OEB, EB-2022-0185, Decision and Rate Order, Section 4, Table 4.1, p. 4. Link.

[84] Calculated as 3.70% - (0.00% + 0.30%) = 3.40%.

C.2.2 Custom IR

Rates are set based on a five-year forecast of a distributor's revenue requirement and sales volume. The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five-year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

- Annual Adjustment Mechanism – the allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including: the distributor's forecasts (revenues and costs, including inflation and productivity); the Board's inflation and productivity analyses; and benchmarking to assess the reasonableness of distributor forecasts. Expected inflation and productivity gains will be built into the rate adjustment over the term.
- Capital Spending – there is no ICM in the Custom IR method. Under this method, distributors are expected to operate under their Board-determined multi-year rates. Under Custom IR, planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term when it commences a new rate-setting cycle. This is consistent with the Board's existing policies in relation to incremental capital under 3rd Generation IR.

C.2.2.1 Example – Hydro One Networks Inc.

Hydro One Networks Inc.'s ("HONI") owns and operates the largest electricity distribution system in Ontario. Its distribution system consists of a lower voltage network of distribution lines, poles, and equipment. It conveys electricity at lower voltages from transformer stations to homes and businesses throughout the province. Hydro One's distribution system services approximately 1.3 million distribution customers and smaller electricity distributors primarily in the rural and remote areas of the province.

HONI's most recent annual rate adjustment application to the board was based on the Custom IR option with a five-year term. The OEB approved a five-year Custom IR framework for HONI that covered the years 2018 to 2022 under a revenue cap index (RCI). As part of that proceeding, the OEB established rates for 2019 and that for subsequent years rates be adjusted mechanistically through a custom revenue cap adjustment formula. The adjustment to rates for the 2022 rate year was based on a productivity factor of 0% and a stretch factor of 0.45% that was to remain constant throughout the term of the plan. Figure 5, below taken from the Decision and Rate Order for the 2022 rates Application, depicts the variables that determine the annual rate adjustment, where:

- I is the inflation factor as determined by the OEB annually;
- X is the productivity factor that is custom to Hydro One; and
- C is Hydro One's customer capital factor, determined to recover the incremental revenue beyond the amount of revenue recovered in base rates necessary to support HONI's DSP in each test year.

Figure 5: RCI by Component[85]

RCI by Component (%)	2020	2021	2022
Inflation Factor (I)	2.00	2.20	3.30
Productivity Factor (X)	-0.45	-0.45	-0.45
Capital Factor (C)	1.21	1.95	1.85
RCI Total	**2.76**	**3.70**	**4.70**

Rates were adjusted for the year 2022 based on the formula RCI = I – X + C, by 4.70%.

C.2.3 Annual IR Index

The Annual IR Index is appropriate for distributors with primarily sustainment investment needs. The Annual IR Index is intended to provide a rate-setting approach that is simpler and more streamlined than the other two. Among other things, there is no forecast cost of service review under this method. Rates are adjusted by a simple price cap index formula. Initial rates are set by applying this adjustment to existing rates. The annual rate adjustments are designed to reflect "steady-state mode" operations – that is, rate adjustments will be comparatively minor. Like other rate setting methods, this method must also include a five-year forecast of capital investments/DSP.

Annual reporting is required from distributors under all three rate setting methods.

- Annual Adjustment Mechanism – under the Annual IR Index rates will be adjusted annually by the growth in an inflation factor minus an X-factor.
- Capital Spending – there is no ICM in the Annual IR Index. The method presumes a largely steady state or sustainment mode of operation by the distributor.

[85] OEB, EB-2021-0032, Decision and Rate Order, Section 4, Table 4.1, p. 5. Link.

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C.2.3.1 Example – ENWIN Utilities Ltd.

ENWIN serves approximately 91,000 mostly residential and commercial electricity customers in the City of Windsor. ENWIN's application for rates for 2019 was made under the Annual IR index option. This adjustment to rates is based on inflation less the Board's highest stretch factor assessment of a distributor's efficiency. Figure 6 below, taken from the Decision and Rate Order for the 2019 rates Application, depicts the variables that determine the annual rate adjustment.

Figure 6: Annual IR Index Adjustment Formula[86]

Components		Amount
Inflation Factor[3]		1.50%
X-Factor	Productivity[4]	0.00%
	Stretch (0.00% – 0.60%)[5]	0.60%

Inserting these components into the formula of inflation factor less X-factor results in an increase of 0.90%[87] to Alectra Utilities' rates for 2023.

C.3 Incremental Capital Modules and Advanced Capital Modules

The Incremental Capital Module ("ICM") exists to address unanticipated, discrete capital expenditures during the IR term. ICM projects are those not included in a distributor's DSP filed during its COS application, or projects included in the DSP lacking sufficient information to address need and prudence at the time of the COS application.

In the past, with the inclusion of ICMs, the OEB observed a tendency for capital projects, especially major ones, to cluster around the test year when the distributor rebases its rates through a COS. In subsequent years, capital spending may be substantially lower than in the bridge and test years, possibly as a means of managing expenses relative to changes in revenues when a price cap formula is used to adjust rates. The concern is that this volatility (i.e., the "roller coaster" effect) in capital investments, to align with rate-regulation schedules, may not align with prudent asset management practice. While some capital investment is "routine" and predictable, major projects like transformer station builds can lead to uneven spending.

[86] OEB, EB-2019-0029, Decision and Rate Order, Section 4, Table 4.1, p. 3. Link.

[87] Calculated as 1.50% - (0.00% + 0.60%) = 0.90%.

Clustering projects around rate resets provides assurance of recovery but may not be optimal from an asset management and rate impact perspective.

Incentivizing distributors to adopt a longer-term planning horizon for capital and operating projects enables resource optimization to serve existing customers while preparing for future needs. Consequently, the OEB decided to advance the review and approval process for incremental capital through the Advanced Capital Module ("ACM"). This adaptation builds on the ICM mechanism. By reviewing eligible discrete capital projects scheduled to go into service during the IR term over the five-year horizon of the DSP, the ACM aims to facilitate enhanced pacing and smoothing of rate impacts.

C.4 Asset Management Process

In Ontario, a distribution utility must employ an asset management process to strategically plan, prioritize, and optimize its capital expenditures while offering various stakeholders' insight into the distributor's asset management process.

An overview specifically of the assets managed by the distribution utility is presented, detailing service area characteristics and providing asset data by type (e.g., capacity, condition, performance, risks, demographics) to justify capital investments and consider economic alternatives. The overview also identifies any prior transmission or high voltage assets deemed as distribution assets and any such assets currently under consideration for such designation:

> *"A distributor should provide an overview of its distribution service area (e.g., system configuration; urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for supporting its capital expenditures over the forecast period. A distributor should provide asset information (e.g., asset capacity and utilization; asset condition; asset failures/performance; asset risks; and asset demographics), by major asset type, that may help explain the specific need for the capital expenditures and demonstrate that a distributor has considered all economic alternatives. There should also be a statement as to whether the distributor has had any transmission or high voltage assets (> 50kV) deemed previously by the OEB as distribution assets, and whether there are any such assets that the distributor is asking the OEB to deem as distribution assets in the present application."* [88]

[88] OEB, Filing Requirements For Electricity Distribution Rate Applications, Chapter 5 – Consolidated Distribution System Plan, Section 5.3 p. 10. Link.

C.4.1 Asset Lifecycle Optimization

An overview of asset lifecycles and the distribution utility's optimization policies and practices evaluates system renewal investments and decisions between refurbishment and replacement. The overview delineates new capital spending and cost-effective refurbishment, along with effective system operations and maintenance efforts to prolong asset life:

> *"The Information provided should be sufficient to show the trade-off between spending on new capital (i.e., replacement) and life-extending refurbishment. A distributor should also be able to demonstrate that it has carried out cost-effective system operations and maintenance (O&M) activities to sustain an asset to the end of its service life…"* [89]

The overview also clarifies methods for cost-effective renewal spending within budget limits, weighing customer reliability needs and capital expenditure risks. The distribution utility must also show forward-looking lifecycle planning to avoid premature replacements due to capacity issues:

> *"A distributor should explain the processes and tools it uses to forecast, prioritize, and optimize system renewal spending and how a distributor intends to operate within budget envelopes. For prioritizing capital expenditures, a distributor should help the audience understand the approaches the distributor uses to balance a customer's need for reliability and capital expenditure costs. A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures.*

> *A distributor should also be able to demonstrate that in planning the lifecycle of an asset, it has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints."* [90]

C.5 Alectra Utilities Corporation Asset Condition Assessment

As part of Alectra's 2022 ICM Application before the OEB, Guidehouse Canada Ltd. submitted a report detailing conclusions and findings of an assurance review of Alectra's five-year investment plan. An element of this report discusses the results of Alectra's 2018 asset condition assessment results:

> *"The determination of asset health via ACA is a key element of Alectra's asset management processes. The DSP documents in detail the methods and level of rigor Alectra currently applies to*

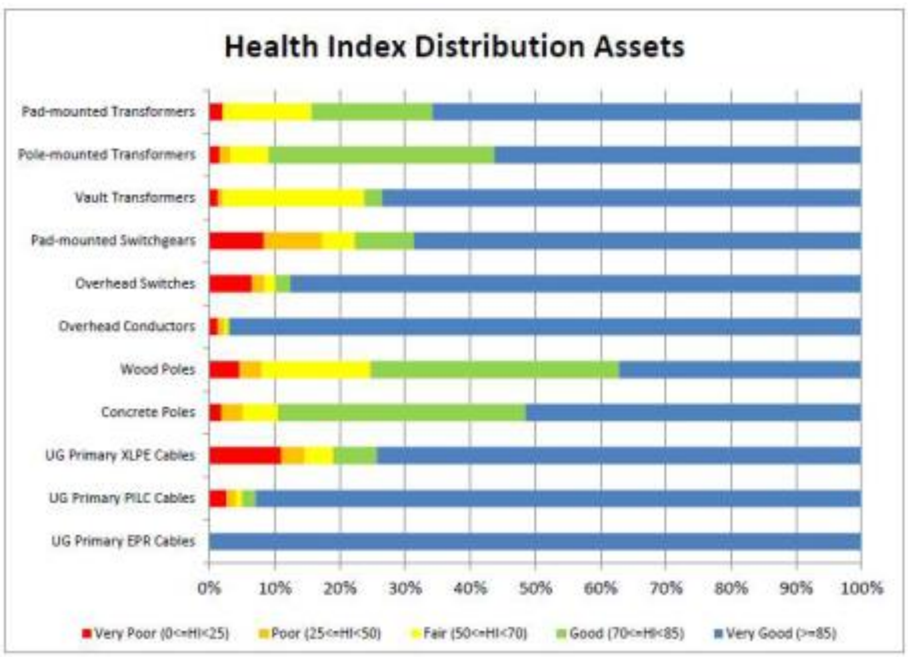
[89] OEB, Filing Requirements For Electricity Distribution Rate Applications, Chapter 5 – Consolidated Distribution System Plan, Section 5.3 p. 10. Link.

[90] OEB, Filing Requirements For Electricity Distribution Rate Applications, Chapter 5 – Consolidated Distribution System Plan, Section 5.3 p. 10. Link.

assess and determine the condition and health of its distribution and station assets.10 Alectra's uses an analytical approach to quantify asset condition as measured by Health Indices (HI) for 11 distribution categories, with asset condition scaled via designations ranging from very poor to very good.

The methodology Alectra uses to derive asset health indices is based on a formulaic approach: HI's are derived based on the product of weighted inspection scores (or percentage scores when more detailed inspection data is available)11 and a conduction multiplier; the latter limits the maximum HI score to reflect safety, obsolescence or field/measurement results. The criteria Alectra applies to determine deterioration levels is based on detailed inspection reports, known risk factors (e.g., defective components), historical performance and expert judgement from staff qualified to assess equipment condition or obsolescence. It is from these processes and HI results that Guidehouse has determined that accelerating the replacement or upgrading of underground assets is required.

The results of Alectra's 2018 asset condition assessments as determined by the HI processes described above appears in Figure 5.2.3. - 1 of the DSP, presented below." [91] [footnotes omitted]



[91] OEB, EB-2022-0013, Application, Attachment 12, Section 1.6, p. 7-8. Link.

C.6 ENWIN Utilities Ltd. PROSPORT Capital Investment Priority List

In its 2020 distribution rate application, ENWIN Utilities Ltd. ("ENWIN") provided a prioritized list of ENWIN's capital investment projects.[92] This list was created by using ENWIN's PROSORT project prioritization tool, which ranks projects based on their cost-effectiveness in risk reduction. The tool calculates a Change in Risk Benefit Factor ("CRBF") for each project by dividing its cost by the change in risk and benefit it provides. Projects with highest risk reduction per unit cost are given higher priority, indicating that they offer a better value proposition for customers. ENWIN considers customer-focused business values when assessing risks, including:

- Safety;
- Financial;
- Reliability; and
- Sustainability.

The PROSORT tool uses a Risk Matrix that combines the consequence and likelihood of a failure to estimate the risk to ENWIN's business values. The Total Risk Score is calculated as the product of the Risk Rating (likelihood multiplied by consequence) multiplied by the weighting of the associated business value. It is important to note that there are certain projects that receive top priority and are exempt from the PROSORT prioritization tool, including Mandatory System Access, System Renewal, and General Plant projects.

- Mandatory System Access projects they must be completed due to license, regulatory directive, contractual commitment, etc.
- Mandatory System Renewable projects, reactive replacements, are considered to be "break-fix" investments which are necessary in order to restore service to existing customers, such as after a storm.
- Mandatory General Plant projects are the ones that provide compliance to regulations.

The following figures are derived from ENWIN's 2020 Capital Investment data, presented in Appendix C.5.

- Figure 7 shows ENWIN's Capital Investment Priority List, illustrating the relationship between project numbers, $/CBRF, and Cumulative Investment in thousands of dollars, illustrating a direct relationship between $/CBRF and ENWIN's Cumulative Investments; and
- Figure 8 illustrates the relationship between ENWIN's project prioritization, $/CRBF, and capital investment.

[92] OEB, EB-2019-0032, Exhibit 2, Section 5.4.3.2, Attachment 2-A, p. 310-311. Link.

Figure 7: ENWIN 2020 Distribution Rates Application – $/CRBF vs. Cumulative Investment[93]

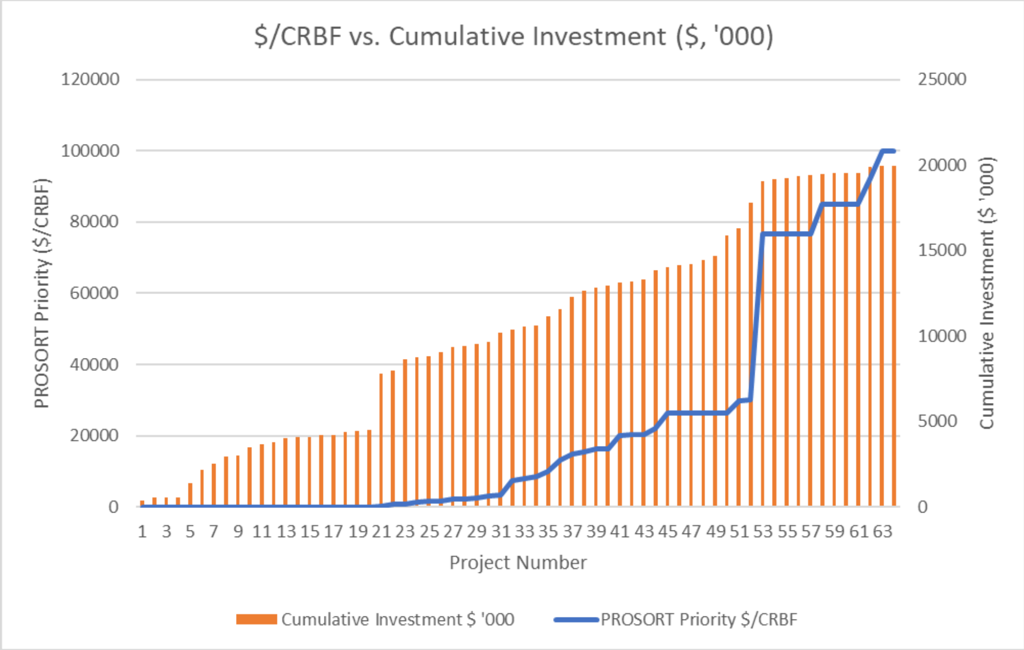


Figure 8: ENWIN 2020 Distribution Rates Application – $/CRBF vs. Capital Investment[94]

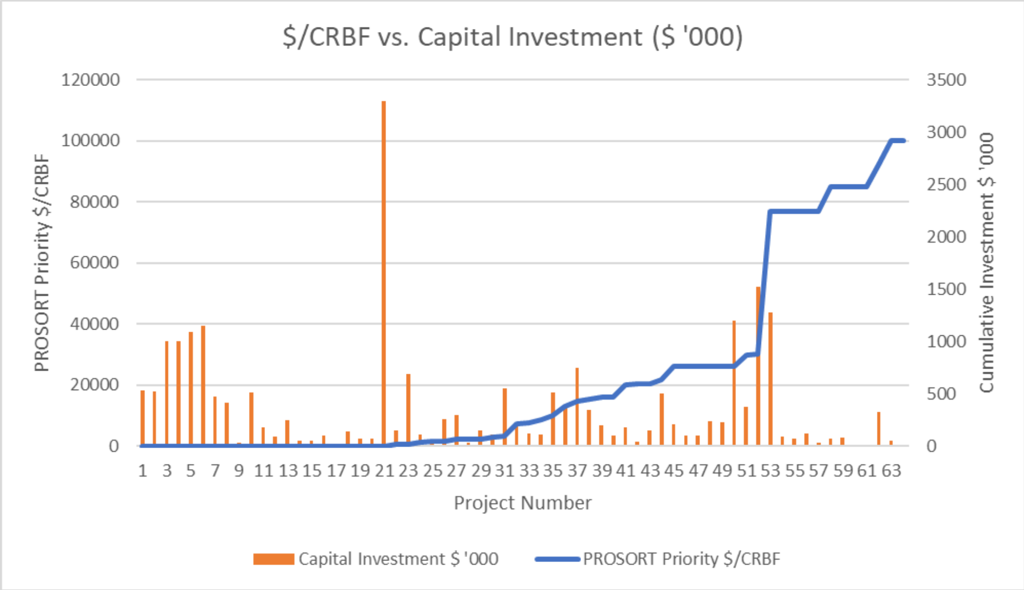


Table 150 from ENWIN's 2020 Distribution Rates Application is presented as Table 27 of this report.

[93] *P0688-D004-MDL-R00-EXT - ENWIN's Capital Investment Priority List Calculations.xlsx* attached.

[94] *P0688-D004-MDL-R00-EXT - ENWIN's Capital Investment Priority List Calculations.xlsx* attached.

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Table 27: ENWIN Utilities Ltd. Example PROSPORT Capital Investment Priority List[95]

2020 Capital Investment by Priority List						
Project Number	2020 Capital Investment Description	Capital Investment Category	Capital Investment $ '000	Capital Contribution $ '000	PROSORT Priority $/CRBF	Cumulative Investment $ '000
1	O/H Customer Connections	System Access	535	(165)	1	370
2	U/G Customer Connections	System Access	525	(335)	1	560
3	Bridge Plaza Relocation	System Access	1,000	(1,000)	1	560
4	Ambassador Bridge Twin Span	System Access	1,000	(1,000)	1	560
5	Road Widening Projects (City Driven Specifics)	System Access	1,090	(260)	1	1,390
6	Riverside Vista Project (City Driven Specifics)	System Access	1,150	(370)	1	2,170
7	Wholesale Metering: Keith TS Feeders	System Access	475	(120)	1	2,525
8	Meter work - new customers (enhancement)	System Access	415		1	2,940
9	Meter work - end of life (sustainment)	System Renewal	35		1	2,975
10	Meter Population Replacement / Upgrade (MIST Meters)	System Access	515		1	3,490
11	Reactive Replacement of Failed Equipment (U/G, O/H)	System Renewal	180		1	3,670
12	Reactive Replacement of Failed Cable	System Renewal	90		1	3,760
13	Reactive Replacement of Transformers	System Renewal	245		1	4,005
14	Reactive Pole Replacement	System Renewal	50		1	4,055
15	Reactive Pole Pulling	System Renewal	50		1	4,105
16	Reactive Hardware Replacement Program	System Renewal	100		1	4,205
17	Reactive Manhole/Vault Rehabilitation	System Renewal	20		1	4,225
18	Retest Smart Meters	System Renewal	145		1	4,370
19	Miscellaneous TS Equipment, EOL Replacement - Reactive	System Renewal	75		1	4,445
20	Weld / Meter Shop / Stores / Garage Misc Site - Reactive	General Plant	75		1	4,520
21	Pole Sustaining Program	System Renewal	3,300		155	7,820
22	Manhole Rebuild Program	System Renewal	150		685	7,970
23	Submersible Sustainment Program	System Renewal	690		790	8,660
24	O/H 3-Phase Transformer Sustainment	System Renewal	110		1,444	8,770
25	Removal of PMH-4 & PMH-Specials	System Renewal	25		1,634	8,795
26	UG PadMount Sustaining Program	System Renewal	255		1,737	9,050
27	Switching Unit Sustaining Program	System Renewal	300		2,206	9,350
28	Radial Branch Backups (23M2 - Single Phase)	System Renewal	35		2,271	9,385
29	Sectionalizing Load Break Switches	System Service	150		2,395	9,535
30	Feeder Tie	System Service	115		3,063	9,650
31	Automating Underground Switching Units	System Service	550		3,378	10,200
32	Green Energy Plan/Walker 2 Reactors - Transfer trip pilot	System Service	200		7,380	10,400
33	Radial Branch Backups (55M1)	System Service	125		7,886	10,525
34	Meter Tank Replacement	System Renewal	110		8,593	10,635
35	Underground Cable Sustainment (Sub Division)	System Renewal	510		9,910	11,145
36	Customer SU Vault Sustainment	System Renewal	400		13,245	11,545
37	Walker Road-Foster to Airport Rd	System Renewal	750		14,778	12,295
38	Conductor Upgrade (23M2 LPT1)	System Service	350		15,338	12,645
39	Vacuum Switch Replacements	System Renewal	200		16,216	12,845
40	CPP Switch Controller Replacements	System Renewal	100		16,216	12,945
41	Conductor Upgrade (55M21 LPT1)	System Service	180		20,013	13,125
42	SCADA Misc Sustaining	System Renewal	45		20,419	13,170
43	SCADA communications Equipment	System Service	150		20,419	13,320
45	Life Cycle Upgrades	General Plant	500		21,917	13,820
46	GIS Evolution and Integration	General Plant	210		26,333	14,030
47	SAP Evolution	General Plant	100		26,333	14,130
48	Network Infrastructure Update and Cyber Security	General Plant	100		26,333	14,230
49	Customer Relationship, Billing and IVR	General Plant	240		26,333	14,470
50	Strategic Enhancements and Tools	General Plant	230		26,333	14,700
51	Feeder Reliability Improvement Project - Prince to Brock	System Service	1,200		26,351	15,900
52	25M7 Feeder Ring Project	System Service	380		29,921	16,280
53	Site Rhodes	General Plant	1,520		30,089	17,800
54	Hydro Operations Vehicles	General Plant	1,280		76,794	19,080
55	Hydro Metering Vehicles	General Plant	95		76,794	19,175
56	Hydro Engineering Vehicles	General Plant	70		76,794	19,245
57	Site Rhodes Vehicles	General Plant	120		76,794	19,365
58	Mail Room Vehicles	General Plant	35		76,794	19,400
59	SCADA FCI's	System Service	70		84,948	19,470
60	Operations Tools	General Plant	85		84,948	19,555
61	Engineering Tools	General Plant	5		84,948	19,560
62	Meter Shop Tools	General Plant	5		84,948	19,565
63	Records Management System	General Plant	330		92,222	19,895
64	Feeder Balancing	System Service	50		100,000	19,945
65	Engineering Power Quality	System Service	5		100,000	19,950

[95] OEB, EB-2019-0032, Exhibit 2, Section 5.4.3.2, Attachment 2-A, Table 150, p. 310. Link.

C.7 Hydro One Networks Inc. Reliability Risk Model[96]

HONI models reliability risk using the relationship between asset demographics, historical asset failures and the impact that equipment has on reliability. Its Reliability Risk Model considers three key inputs:

1) Asset-specific Hazard Curves: indicates the likelihood of an asset failing, including retirements, within a year, considering that the asset has continued to function in the preceding years. Different asset classes have distinct hazard rates.
2) Asset Demographics: estimates the likelihood of failure or deterioration requiring replacement for each asset class when utilized with asset-specific hazard curves.
3) The total amount of units to be replaced.

The reliability risk model generates a system-wide reliability risk measure that serves as a general indicator of total system reliability risk. It is not intended for making individual investment decisions, which are determined through a comprehensive asset risk assessment process.[97] The model provides a directional indicator of reliability risk and relies on hazard curves derived from HONI's asset removal history.

C.8 Performance Measurement for Electricity Distributors

In a Report of the OEB,[98] system reliability performance objectives are measured through a Scorecard method to facilitate performance monitoring and distributor benchmarking:

> *"As described in the OEB's approach to measuring distributor performance, (the Scorecard Report), in order to facilitate performance monitoring and eventually distributor benchmarking, the OEB is using a scorecard approach to effectively translate the four outcomes of the renewed regulatory framework into a coherent set of performance measures. This approach effectively organizes performance information in a manner that assists easy evaluations and meaningful comparisons.*
>
> *Distribution system reliability performance measures and expectations are one of the keys to measuring distributors' performance and assessing the achievement of the Operational Effectiveness outcome.*

[96] OEB, EB-2016-0160, Exhibit B1, Tab 2, Schedule 4, Attachment 1, p. 1-6. Link.

[97] This process considers various factors, including asset condition, demographics, equipment performance, criticality, economics, utilization, obsolescence, environmental risks, compliance obligations, equipment defects, health and safety considerations, and customer preferences.

[98] OEB, EB-2010-0379. Link.

The Scorecard includes two of the OEB's existing system reliability indicators: SAIDI (Loss of Supply) and SAIFI (Loss of Supply). To improve understandability and transparency for customers, these measures are referred to respectively on the Scorecard as:

- *Average Number of Hours that Power to a Customer is Interrupted*
- *Average Number of Times that Power to a Customer is Interrupted*

As stated in the Scorecard Report, each measure included on the Scorecard will have an established minimum level of performance that a distributor is expected to achieve. The original performance levels associated with the two reliability indicators were that a distributor will remain within the range of its historical performance. The policy set out in this Report will establish a new minimum level of performance for these measures.

The introduction of specific reliability performance objectives will establish the level of performance a distributor will be expected to deliver. Continuous improvement will be demonstrated by a distributor's ability to deliver improved reliability performance without an increase in costs, or maintain the same level of performance at a reduced cost." [99]

C.9 Distribution and Transmission Reliability Indices

The OEB specifies filing requirements for distribution system plans for electricity distribution cost of service rate applications, including requirements for service quality and service reliability indicators. A distributor (the applicant) is required to provide reported reliability indicators for the last five historical years. Furthermore:

> *"A distributor should also provide explanations for material changes in service quality and reliability, and whether and how the DSP addresses these issues. The OEB expects any five-year declining trends in reliability for SAIDI and SAIFI to be explained. If a distributor has reliability targets established in a previously filed DSP, as described below, any under-performance should also be explained."* [100]

An overview of historical performance utilizing the aforementioned methodologies and metrics/targets, highlighting trends observed throughout the period, is also required. OEB's filing requirements stipulate the following data to be provided:

- *"All interruptions*
- *All interruptions excluding loss of supply*

[99] OEB, EB-2014-0189, Section 2.1, p. 4. Link.

[100] OEB, Filing Requirements for Electricity Distribution Rate Applications, Chapter 5 – Distribution System Plan, p. 7. Link.

- *All interruptions excluding Major Events and loss of supply for the following:*
- *The distribution system average interruption frequency index (SAIFI)*
- *System average interruption duration index (SAIDI)*

> *The applicant should also provide a summary of Major Events that occurred since the last Cost of Service (CoS) filing.*
>
> *For each cause of interruption, a distributor should, for the last five historical years, report the following data:*

- *Number of interruptions that occurred as a result of the cause of interruption*
- *Number of customer interruptions that occurred as a result of the cause of interruption*
- *Number of customer-hours of interruptions that occurred as a result of the cause of interruption"* [footnotes omitted][101]

There are additional, distributor specific reliability targets to be considered as established in "Report of the OEB: Electricity Distribution System Reliability Measures and Expectations"[102]:

> *"…distributors' SAIDI and SAIFI performance is expected to meet the performance target set out in the Scorecard. Distributors who wish to establish performance expectations based on something other than historical performance should provide evidence of their capital and operational plan and other factors that justify the reliability performance they plan to deliver. Distributors should also provide a summary of any feedback from their customers regarding the reliability of the distributor's system.*
>
> *Distributors who wish to use SAIDI and SAIFI performance benchmarks that are different than the historical average must provide evidence to support the reasonableness of such benchmarks."* [103,104]

[101] OEB, Filing Requirements for Electricity Distribution Rate Applications, Chapter 5 – Distribution System Plan, p. 7-8. Link.

[102] OEB, EB-2014-0189. Link.

[103] OEB, Filing Requirements for Electricity Distribution Rate Applications, Chapter 5 – Distribution System Plan, p. 8. Link.

[104] Please refer to Appendix C.1 for an overview of the Scorecard approach employed by the OEB.

APPENDIX D: NEWFOUNDLAND OVERVIEW

Table 28 provides an overview of the Newfoundland & Labrador Regulator and prominent utilities considered in this report.

Table 28: Newfoundland and Labrador Board of Commissioners of Public Utilities Overview

Category	Description	Hyperlink
Regulator	Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB")	Link
Areas of Oversight	Electric utilities, automobile insurance, petroleum	Link
Electric Utilities	Newfoundland and Labrador Hydro (“NL Hydro”)	Link
	Newfoundland Power (“NP”)	Link

Table 29 summarizes applicable statutes and legislation of Newfoundland & Labrador that govern the NLPUB and electric utilities.

Table 29: Newfoundland & Labrador – Statues & Legislation

Statute & Legislation	Hyperlink
NLPUB	
The Public Utilities Act, RSNL1990 Chapter P-47	Link
The Public Utilities Act – Regulations	Link
The Electrical Power Control Act	Link
Electrical Power Control Act, 1994 - Regulations	Link
Public Utilities Acquisition of Lands Act	Link
Hydro	
Hydro Corporation Act	Link

Table 30 summarizes applicable rules, procedures and guidelines for the NLPUB.

Table 30: Newfoundland & Labrador – Rules, Procedures and Guidelines

Rules, Procedures and Guidelines	Hyperlink
NLPUB	
Capital Budget Application Guidelines	Link
Hearing Guidelines	Link
Newfoundland Power	

Rules, Procedures and Guidelines	Hyperlink
Schedule of Rates, Rules and Regulations	Link
Residential and General Service CIAC Policies	Link
Inter-Affiliate Code of Conduct	Link

Table 31 summarizes applications to the NLPUB considered in this report.

Table 31: Example NLPUB Applications Considered

Proceeding	Hyperlink
Newfoundland & Labrador Hydro	
2023 Capital Budget Application	Link
2022 Capital Budget Application	Link
2021 Capital Budget Application	Link
2020 Capital Budget Application	Link
2019 Capital Budget Application	Link
2018 Capital Budget Application	Link
2017 Capital Budget Application	Link
2016 Capital Budget Application	Link
2015 Capital Budget Application	Link
2014 Capital Budget Application	Link[105]
2013 Capital Budget Application	Link
Newfoundland Power	
2023 Capital Budget Application	Link
2022 Capital Budget Application	Link
2021 Capital Budget Application	Link
2020 Capital Budget Application	Link
2019 Capital Budget Application	Link
2018 Capital Budget Application	Link
2017 Capital Budget Application	Link
2016 Capital Budget Application	Link
2015 Capital Budget Application	Link
2014 Capital Budget Application	Link
2013 Capital Budget Application	Link

[105] Not considered in this report due to broken hyperlink on the NLPUB's Archived Proceedings page.

Proceeding	Hyperlink
2012 Capital Budget Application	Link

D.1.1 Newfoundland Hydro – Capital Budget Applications

Table 32 presents a summary of Newfoundland Hydro's capital budget approvals from 2013 to 2023.

Table 32: Newfoundland Hydro Applications Considered

Proceeding	Decision & Order	Proposed Budget ($)	Approved Budget ($)
2023 Capital Budget Application	P.U. 2(2023)	$90,828,700.00	$90,828,700.00
2022 Capital Budget Application	P.U. 37(2021)	$84,714,000.00	$84,163,400.00
2021 Capital Budget Application	P.U. 2(2021) P.U. 11(2021)	$107,452,400.00	$107,452,400.00
2020 Capital Budget Application	P.U. 6(2020)	$108,487,300.00	$107,576,100.00
2019 Capital Budget Application	P.U. 46(2018)	$116,140,700.00	$116,140,700.00
2018 Capital Budget Application	P.U. 43(2017) P.U. 5(2018) P.U. 9(2018) P.U. 9(2019)	$198,925,200.00	$181,193,700.00
2017 Capital Budget Application	P.U. 45(2016)	$271,265,600.00	$271,265,600.00
2016 Capital Budget Application	P.U. 33(2015)	$183,082,800.00	$183,082,800.00
2015 Capital Budget Application	P.U. 50(2014)	$76,832,900.00	$76,832,900.00
2014 Capital Budget Application	Not considered in this report due to broken hyperlink on the NLPUB's Archived Proceedings page.		
2013 Capital Budget Application	P.U. 2(2013) P.U. 4(2013)	$66,144,800.00	$62,272,500.00
	Sum:	**$1,391,736,400.00**	**$1,357,801,100.00**

Where applicable, the following discussion summarizes disallowances for each of the reviewed Capital Budget Applications from 2012 to 2023:

- 2023 Capital Budget Application: No disallowances.

- 2022 Capital Budget Application:[106] The Application proposed $550,600 for the "Additions for Load (2022)-Distribution System-Mary's Harbour Voltage Conversion" project for converting the voltage of the Mary's Harbour distribution system from 4.16 kV to 25 kV. The project was deferred, at the suggestion of NLH, based on NP's submission that consideration of this project should be deferred until a decision has been rendered on Hydro's "Long-Term Supply for Southern Labrador-Phase 1" application.
- 2021 Capital Budget Application: No disallowances.
- 2020 Capital Budget Application: The Application proposed $175,600 for the "Diesel Plant Fire Protection (2020-2021)" project, proposed to install an automated fire protection system in the Charlottetown Diesel Generating Plant to mitigate the risk of a fire destroying or damaging equipment. Additionally, the Application proposed $734,700 for the "Purchase New Mobile Substation - Bishop's Falls" project, which proposed a procurement of a mobile substation, designed to accommodate numerous terminal stations and transformers located throughout Hydro's interconnected system, to mitigate a risk of extended outages to NLH customers.
    - The Diesel Fire Plant Protection project was withdrawn by NLH due to a fire at the diesel plant.[107]
    - For the New Mobile Substation project, the Board observed that the utilities effectively optimized the utilization of mobile substations, thereby preventing any instances where a mobile substation was not accessible when needed. Although NLH presented data indicating instances when a spare unit was not available, they did not address whether adopting a different approach to capital and maintenance scheduling in the future could guarantee the availability of at least one unit. Given these circumstances, the Board concluded that Hydro had not proven that acquiring a mobile substation aligns with the goal of providing the most cost-effective and dependable service and disallowed the project.[108]
- 2019 Capital Budget Application: No disallowances.
- 2018 Capital Budget Application: The Application proposed $23,513,900 (then reduced to $17,731,500 in a revised project proposal)[109] for the "Muskrat Falls to Happy Valley Interconnection Project", which involved splitting TL240,[110] the 138 kV transmission line extending from the Churchill Falls Terminal Station to the Happy Valley Terminal Station. The ends of this division were to be terminated within a Hydro-constructed ring bus situated in the Muskrat Falls 315 kV Terminal

[106] Order P.U. 37(2021), p. 11, l. 7-9. Link.

[107] Order P.U. 6(2020), Footnote 2, p. 3. Link.

[108] Order P.U. 6(2020), p. 6, l. 37 to p. 7, l. 36. Link.

[109] Ibid, Footnote 1, p. 2.

[110] TL240 is also known in the Labrador Interconnected System as L1301 and L1302. L1301 is from Churchill Falls Terminal Station to the Muskrat Falls Tap Station, and L1302 is from the Muskrat Falls Tap Station to Happy Valley Terminal Station.

Station. Additionally, the Application proposed $10,325,400 for the "Hydraulic Generation Refurbishment and Modernization", which encompasses the refurbishment and modernization of hydraulic generation systems, ensuring their optimal performance and contemporary functionality.

- The Muskrat Falls interconnection project was disallowed due to insufficient evidence of its necessity and cost-effectiveness. To facilitate a comprehensive assessment, the Board required additional information from NLH. This information should have covered short-term and long-term concerns, including costs tied to various aspects of the project. Furthermore, NLH needed to demonstrate how the proposed project addressed system requirements, particularly given unresolved issues related to projected load increases. Consequently, project consideration was deferred, pending the submission of specified information.[111]
  - In a subsequent Order, the Board once more determined that the Project should be postponed pending additional information from NLH. The Board highlighted that despite significant forecasted load increases and associated costs, NLH had not developed a comprehensive plan to handle load growth and ensure reliability on the Labrador Interconnected system.[112]
  - In a subsequent Order, the Board approved the capital expenditures for the Muskrat Falls interconnection project, as the Board was content with Hydro's provided information indicating reliability and capacity concerns in Labrador East. The Board concluded that the Project was the least-cost solution to address these issues, deeming it necessary for reliable service and load requirements.[113]
- In the Application, NLH combined 12 hydraulic generation refurbishment and modernization projects into one two-year project with estimated expenditures of $10,325,400 in 2018. The new presentation approach for hydraulic generation projects, in alignment with Hydro's asset management program, was appreciated for categorizing assets by classification. Despite recognizing the intent to improve regulatory efficiency and focus, the Board found that this presentation did not aid in its review of the proposed hydraulic generation capital work and did not satisfy the requirements of the legislation and was not consistent with the Capital Budget Application Guidelines.[114] In a subsequent Order, NLH's proposed capital expenditures for this project received approval, as the Board was content with the enhanced format of the data, which led to clearer comprehension of the twelve individual projects. The revised information aligned with the demands of the legislation and the Capital Budget

[111] Order P.U. 43(2017), Section 4.3, p. 11, l. 15 to p. 13, l. 2. Link.

[112] Order P.U. 9(2019), p. 6, l.27-31. Link.

[113] Order P.U. 9(2019), p. 8, l. 5-16. Link.

[114] Order P.U. 43(2017), Section 4.4, p. 13, l. 4 to p. 15, l. 27. Link.

Guidelines, adequately outlining the proposed expenses, individual justifications, and potential alternatives.[115]

- 2017 Capital Budget Application: No disallowances.
- 2016 Capital Budget Application: No disallowances.
- 2015 Capital Budget Application: No disallowances.
- 2014 Capital Budget Application: Not considered in this report due to broken hyperlink on the NLPUB's Archived Proceedings page.
- 2013 Capital Budget Application: The Application originally proposed five projects totalling $3,400,200 associated with the Holyrood Thermal Generating Station ("Holyrood") which were then withdrawn by NLH:[116]
    - Upgrade Governor Controls on Units 1 and 2 for $1,455,500;
    - Upgrade Vibration Monitoring Equipment for $519,900;
    - Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 for $50,000;
    - Install Fire Protection Upgrades for $267,200; and
    - Rewind Generator Units 1 and 2 for $1,107,600.

  Additionally, NLH proposed to capitalize Front End Engineering Design ("FEED") costs in 2013 in the amount of $472,100 associated with the preparation of the 2014 capital budget submission. FEED represents Phase I engineering for a project, transitioning from concept to a defined plan. Hydro maintained that conducting more thorough FEED work before project approval could lead to better project definition, planning, and cost estimates, minimizing surprises during the final design and execution stages. Ultimately, the Board determined that the proposed project of pre-approving FEED costs was unnecessary. While agreeing that FEED costs could be capitalized in line with International Financial Reporting Standard ("IFRS"), the Board suggested that these costs should be addressed during the capital budget consideration for the respective year, allowing a comprehensive review of project details and addressing transparency concerns. Thus, the Board did not approve the proposed project as presented.

D.1.2 Newfoundland Power – Capital Budget Applications

Table 33 presents a summary of Newfoundland Power's capital budget approvals from 2012 to 2023.

[115] Order P.U. 5(2018), p. 3, l. 3-4. Link.

[116] Order P.U. 4(2013), p. 2, l. 5-15. Link.

Table 33: Newfoundland Power Applications Considered

Proceeding	Decision & Order	Proposed Budget ($)	Approved Budget ($)
2023 Capital Budget Application	P.U. 38(2022)	$123,463,000	$122,869,000
2022 Capital Budget Application	P.U. 36(2021)	$109,651,000.00	$108,121,000.00
2021 Capital Budget Application	P.U. 37(2020) P.U. 10(2021) P.U. 12(2021)	$111,298,000.00	$94,601,000.00
2020 Capital Budget Application	P.U. 5(2020)	$96,614,000.00	$96,614,000.00
2019 Capital Budget Application	P.U. 35(2018)	$93,304,000.00	$93,304,000.00
2018 Capital Budget Application	P.U. 37(2017)	$83,876,000.00	$83,876,000.00
2017 Capital Budget Application	P.U. 39(2016)	$89,411,000.00	$89,411,000.00
2016 Capital Budget Application	P.U. 23(2015)	NP filed a Deferred Cost Recovery Application requesting approval to change the date that Newfoundland Power is required to file its next general rate application from June 1, 2015, to June 1, 2016 and to base the application on a 2017 test year rather than a 2016 test year. The Application also requests approval of a 2016 cost recovery deferral of $3,991,000. The application was denied by the Board.	
2015 Capital Budget Application	P.U. 40(2014)	$94,211,000.00	$94,211,000.00
2014 Capital Budget Application	P.U. 27(2013)	$84,462,000.00	$84,462,000.00
2013 Capital Budget Application	P.U. 21(2012)	$80,788,000.00	$80,788,000.00
2012 Capital Budget Application	P.U. 26(2011)	$77,293,000.00	$77,293,000.00
	Sum:[117]	**$1,044,371,000.00**	**$1,025,550,000.00**

Where applicable, the following discussion summarizes disallowances for each of the reviewed Capital Budget Applications from 2012 to 2023:

- 2023 Capital Budget Application:[118] The Application proposed capital expenditures of $594,000 for the EV Charging Network project. On November 10, 2022, subsequent to submissions on the Application, the Board issued Order No. P.U. 33(2022)[119] concerning approvals for Newfoundland

[117] Does not consider the 2016 Capital Budget Application.

[118] Order P.U. 38(2022, p. 28, l. 34 to p. 39, l. 38. Link.

[119] Order P.U. 33(2022), p. 17. Link

Power and Hydro's conservation, demand management, and electrification programs. The Board highlighted unresolved issues related to Electric Vehicle ("EV") charging infrastructure, including accounting treatment and cost recovery. The Board emphasized the need for comprehensive consideration of utility EV charging station expenditures, allowing utilities to seek approvals for 2022 and 2023, including Newfoundland Power's outstanding capital requests for EV charging stations. Acknowledging Newfoundland Power's 2023 expenditure request, the Board mandates necessary approvals for the proposed 2023 charging infrastructure, following its determination in Order No. P.U. 33(2022).

- 2022 Capital Budget Application:[120] The Application proposed $47,744,000 in distribution expenditures in which was reduced by $1,530,000 due to the removal of the EV Charging Network project to be considered in a separate process. Distribution expenditures encompass distribution line extensions, meter and wire installations, street lighting upgrades, transformer purchases, line rebuilds, structure reconstruction, and equipment relocation. Also covered are load growth feeders, distribution automation, LED lighting replacements, the Distribution Reliability Initiative, Humber substation system conversion to 12.5 kV and construction fund allowances.
- 2021 Capital Budget Application:[121] The Application proposed capital expenditures of $6,794,000 for the construction of a new substation for St. John's North-Portugal Cove, including expenditures related to transmission, distribution and telecommunications include the construction of transmission line extensions, fibre optic cables for transmission line protection, SCADA monitoring and remote control, upgrading an existing distribution feeder and constructing new aerial distribution exits. The Application also proposed $9,903,000 for the Customer Service System Replacement project. The Board announced a technical conference for proposed Customer Service System replacement expenditures. To facilitate timely consideration of Newfoundland Power's 2021 Capital Budget Application, these expenses would be discussed in a distinct Board order. Both expenditures were approved in subsequent Orders P.U. 10(2021) and P.U. 12(2021), respectively.
- 2020 Capital Budget Application: No disallowances.
- 2019 Capital Budget Application: No disallowances.
- 2018 Capital Budget Application: No disallowances.
- 2017 Capital Budget Application: No disallowances.
- 2016 Capital Budget Application:[122] The application was denied by the Board.
- 2015 Capital Budget Application: No disallowances.
- 2014 Capital Budget Application: No disallowances.

[120] Order P.U. 36(2021), p. 20, l. 21-22. Link.

[121] Order P.U. 10(2021), p. 2, l. 43-44. Link & Order P.U. 12(2021), p. 11, l. 18-20, Link.

[122] Order P.U. 23(2015), p. 6, l. 38. Link.

- 2013 Capital Budget Application: No disallowances.
- 2012 Capital Budget Application: No disallowances.

APPENDIX E: NOVA SCOTIA OVERVIEW

Table 34 provides an overview of the Nova Scotia Regulator and prominent utilities considered in this report.

Table 34: Nova Scotia Utility and Review Board Overview

Category	Description	Hyperlink
Regulator	Nova Scotia Utility and Review Board ("NSUARB")	Link
Areas of Oversight	Auto Insurance, Criminal Injuries, Electricity, Expropriation Compensation, Film Classification, Fire Safety, Gaming, Gasoline and Diesel Pricing, Halifax-Dartmouth Bridge Commission, Liquor Licensing, Motor Carrier – Passenger, Municipal & School Board Boundaries, Natural Gas, Payday Loans, Planning, Property Assessment Appeals, Railways, Water, Wastewater & Stormwater	Link
Electric Utilities	Nova Scotia Power Inc. ("NSPI")	Link

Table 35 summarizes applicable statutes and legislation of Newfoundland & Labrador that govern the NLPUB and electric utilities.

Table 35: Nova Scotia – Statues & Legislation

Statute & Legislation	Hyperlink
General	Link
Utility and Review Board Act	Link
Public Utilities Act	Link
Electricity Act	Link
Consumer Protection Act	Link
Nova Scotia Power Privatization Act	Link
Efficiency Nova Scotia Corporation Act	Link
Electricity Efficiency and Conservation Restructuring (2014) Act	Link
Renewable Electricity Regulations	Link

Table 36 summarizes applicable rules, procedures and guidelines for the NLPUB.

Table 36: Nova Scotia – Rules, Procedures and Guidelines

Rules, Procedures and Guidelines	Hyperlink
Electricity Processes - Overview	Link

Rules, Procedures and Guidelines	Hyperlink
Board Regulatory Rules	Link
Municipal Utilities - User Guide	Link
Customers / Public - Electricity User Guide	Link
NSPI ACE Plan - Q&A	Link
NSPI General Information on Setting Rates	Link
Integrated Resource Planning	Link
Preparing a Rate Case - Process Overview	Link

Table 37 summarizes applications to the NLPUB considered in this report. Archived documents for each proceeding are available through NSUARB's Public Documents Database.[123]

Table 37: Example NSUARB Applications Considered[124]

Utility	Proceeding	Matter No.
Nova Scotia Power Inc.	2023 Annual Capital Expenditure ("ACE") Plan	M11017
Nova Scotia Power Inc.	2022 Annual Capital Expenditure ("ACE") Plan	M10366
Nova Scotia Power Inc.	2021 Annual Capital Expenditure ("ACE") Plan	M09920
Nova Scotia Power Inc.	2020 Annual Capital Expenditure ("ACE") Plan	M09499
Nova Scotia Power Inc.	2019 Annual Capital Expenditure ("ACE") Plan	M08984
Nova Scotia Power Inc.	2018 Annual Capital Expenditure ("ACE") Plan	M08350
Nova Scotia Power Inc.	2017 Annual Capital Expenditure ("ACE") Plan	M07745
Nova Scotia Power Inc.	2016 Annual Capital Expenditure ("ACE") Plan	M07176
Nova Scotia Power Inc.	2015 Annual Capital Expenditure ("ACE") Plan	M06514
Nova Scotia Power Inc.	2014 Annual Capital Expenditure ("ACE") Plan	M05998

E.1.1 Nova Scotia Power Inc. – Annual Capital Expenditure Plans

Table 33 presents a summary of NSPI's ACE Plan approvals from 2014 to 2023.

[123] NSUARB. Link.

[124] NSUARB, *Nova Scotia Power Capital Expenditures*. Link.

Table 38: Nova Scotia Power Inc. Applications Considered

Proceeding	Order	Proposed Routine Capital Expenditures	Proposed Capital Project Expenditures	Approved Routine Capital Expenditures	Approved Capital Project Expenditures
2023 ACE Plan	M11017 Order	$126,037,338	$39,906,303	$121,772,225	$39,906,303
2022 ACE Plan	M10366 Order	$110,533,578	$70,614,010	$110,533,578	$70,614,010
2021 ACE Plan	M09920 Order	$94,090,144	$52,962,331	$94,090,144	$52,962,331
2020 ACE Plan	M09499 Order	$84,337,800	$83,065,002	$84,337,800	$83,065,002
2019 ACE Plan	M08984 Order	$82,312,222	$108,104,362	$82,312,222	$108,104,362
2018 ACE Plan	M08350 Order	$83,861,643	$120,120,344	$83,861,643	$118,344,069
2017 ACE Plan	M07745 Order	$80,167,979	$72,601,321	$80,167,979	$72,601,321
2016 ACE Plan	M07176 Order	$81,990,925	$92,452,908	$79,596,464	$87,278,325
2015 ACE Plan	M06514 Order	$73,097,621	$83,627,912	$72,397,621	$83,627,912
2014 ACE Plan	M05998 Order	$72,275,566	$24,851,650	$72,275,566	$24,772,304
	Sum:	**$888,704,816**	**$748,306,143**	**$881,345,242**	**$741,275,939**

Where applicable, the following discussion summarizes disallowances for each of the reviewed Capital Budget Applications from 2014 to 2023. NSPI's capital budget is comprised of:

1. Routine Capital Expenditures; and
2. Capital Project Expenditures.

E.1.1.1 Routine Capital Expenditures

- 2023 ACE Plan:[125] The Application proposed $8,513,734 for Project #D008 – "Provincial Storm" for storm response and reactive work pertaining to distribution upgrade and replacements for 2023, formulated using a five-year average of past expenditure levels, excluding instances of Extreme Event Day storms, and accounting for an annual inflation rate of 3.5%.[126] The Board disallowed $4,265,113, citing the median of the total annual expenditures in this routine over the past five years, adjusted for inflation.
- 2022 ACE Plan: No disallowances.
- 2021 ACE Plan: No disallowances.
- 2020 ACE Plan: No disallowances.
- 2019 ACE Plan: No disallowances.

[125] NSUARB Matter No. M11017, Order, p. 1.

[126] NSPI noted the amount can vary significantly due to the fluctuations in annual storm activity.

- 2018 ACE Plan: No disallowances.
- 2017 ACE Plan: No disallowances.
- 2016 ACE Plan:[127] The Application proposed $2,994,461 for Project #D010 – "Distribution Right of Way Widening" for managing vegetation to reduce the frequency and duration of outages, all the while striving to enhance accessibility to NSPI's distribution system. NSPI raised the distribution Routine budget by approximately $2.4M beyond the allocated $600,000 in the 2015 ACE Plan forecast. Consequently, NSPI is trimming its operating expenses by $2.4 million in 2016, leading to higher profits and an associated rise in its rate base. This action would lead to higher rates, a decision not sanctioned by the Board. Consequently, the Board decided to bring the routine budget for Project #D010 in line with the $600,000 amount set in the 2015 ACE Plan forecast.
- 2015 ACE Plan:[128] The Application proposed $600,00 for Project #T010 – "Transmission Right of Way Widening" for managing vegetation to reduce the frequency and duration of outages, all the while striving to enhance accessibility to NSPI's transmission system. Additionally, the Application proposed $3,105,000 for a routine capital spending activity "Property Improvements and Furniture".
    - Project #T010 was withdrawn for reconsideration pending the conclusion of the Arthur proceeding as agreed in NSPI's Reply evidence.
    - The routine capital spending activity "Property Improvements and Furniture" was reduced by $100,000 account for connection of Discovery Centre to NS Power offices at 1223 Lower Water Street.
- 2014 ACE Plan: No disallowances.

E.1.1.2 Capital Project Expenditures

- 2023 ACE Plan: No disallowances.
- 2022 ACE Plan: No disallowances.
- 2021 ACE Plan: No disallowances.
- 2020 ACE Plan: No disallowances.
- 2019 ACE Plan: No disallowances.
- 2018 ACE Plan:[129] The Application proposed $1,776,275 for Project #52143 – "LM6000 Engine 191-332 Hot Section" for hot section refurbishment, through component replacement, of Engine 191-332 from the LM6000 Combustion Turbine Units. The project was removed at the request of NSPI due to a Consensus document, a resolution of all issues between the signatories related to the 2018 ACE

[127] NSUARB Matter No. M07176, Board Decision, para. 75, p. 18.

[128] NSUARB Matter No. M06514, Board Decision, para. 43-45, p. 12 & para. 106, p. 26.

[129] NSUARB Matter No. M08350, Board Decision, para. 11, p. 6 & para. 81-82, p. 20.

Plan, which did not include one capital work order originally included in the Application (Project #52143), and subsequently withdrawn in the Response to NSUARB IR-79.

- 2017 ACE Plan: No disallowances.
- 2016 ACE Plan:[130] The Application proposed $604,193 for Project #47613 – "PHB[131] – Boiler Refurbishment 2016" and $296,556 for Project #47614 – "PHB Fuel System Refurbishment 2016" in an effort to ensure reliable operation of the boiler and supporting fuel system.
  - Project #47613 – replacements will focus on the fuel insertion screw conveyors, boiler reciprocating grate, and pressure parts of the boiler. For the electrostatic precipitator, improvements will be made to the collecting system alignment, casing repairs to minimize air ingress, and the replacement of precipitator outlet expansion joints.
  - Project #47614 - Replacement of hydraulic and structural components on the truck dumpers, as well as belts, chains, and drivetrain parts on the conveyors, is crucial to maintain a continuous flow of biomass fuel to the boiler. The plan involves annual replacement of portions of these components on a rotating basis.

  On April 8, 2016, the government amended the Renewable Electricity Regulations. One of the amendments had the effect of removing "must run" designation on the PHB plant. As a result, the Board instructed NSPI to reassess all plant-related capital undertakings. Consequently, the authorization for funding two projects was suspended, and they were earmarked for individual evaluation. The Port Hawkesbury project, which falls below $250,000, along with its associated routine tasks, was also subject to a prudency review.
- 2015 ACE Plan: No disallowances.
- 2014 ACE Plan:[132] The Application proposed $936,380 for Project #43672 – "82V-T1 Transformer Rewind" for proactively rewinding 82V-T1 to prevent a forced outage resulting from mechanical failure of internal coil blocking. The originally proposed project cost was adjusted to $857,034 due to NSPI's corrections to its cost estimate.[133]

E.2 NSPI Distribution and Transmission Reliability Indices

NSPI's Capital Expenditure Justification Criteria ("CEJC") specifies requirements for capital planning, which provides a standard ranking methodology for Generation, Transmission, Distribution, and Information Technology investments:

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[130] NSUARB Matter No. M07176, Board Decision, para. 55-56, p. 14.

[131] Port Hawkesbury Biomass.

[132] NSUARB Matter No. M05998, Board Decision, para. 38, p. 11.

[133] NSUARB Matter No. M05598, NSPI Reply Evidence, Section 2.6, l. 23-33, p. 7.

"Pursuant to Section 6.1 of the CEJC, NS Power's generation, transmission and distribution capital projects are rated according to the following criteria:

- *Health and Safety: Regulatory Requirements, Operating Permits, Protection of Equipment and Personnel Safety, and JOHSC actions.*
- *Environment/Regulatory Compliance: Renewable Energy Standards, Greenhouse Gas (GHG) Regulations, or Air Emission Regulations.*
- *Business Sustainability: SAIDI, SAIFI, CAIDI; unit reliability; system upgrade requirements; code requirements; NERC/NPCC Requirements, or economics (based on payback period, and revenue requirement); requirement to serve."* [emphasis added][134]

Refer to Table 39 where NSPI considers SAIDI, SAIFI, and the Customer Average Interruption Duration Index ("CAIDI") as primary reliability indices to gauge performance in its distribution and transmission systems. Projects aimed at enhancing customer reliability are assessed based on probability factors associated with these performance targets.

Table 39: NSPI Distribution and Transmission Reliability Indices

Index	Description
SAIDI	A measure of the amount of time, in hours, an average distribution customer is without power in a year.
SAIFI	A measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience in a year.
CAIDI	A measure of the average outage duration that any given customer would experience. Calculated as SAIDI divided by SAIFI.

The SAIDI and SAIFI targets established by NSPI are based on various factors, incorporating long-term historical reliability trends and performance for the current year. These targets also account for the yearly fluctuations attributed to weather conditions. Additionally, NSPI maintains the consistency of its SAIDI and SAIFI metrics by considering the effects of storms and excluding "major and extreme" events to ensure comparability.

[134] NSPI, M11017, 2023 ACE Plan, Exhibit N-1, Section 11.1.2, p. 74, l. 6-17. Link.

APPENDIX F: OFFICE OF THE CONSUMER ADVOCATE SCOPING LETTER

Attached on the following pages is a copy of the scoping letter provided by the Consumer Advocate for this report.

Office of the Consumer Advocate

PO Box 23135
Terrace on the Square
St. John's, NL Canada
A1B 4J9

Tel: 709-724-3800
Fax: 709-754-3800

July 18, 2023

Via Email

Midgard Consulting Inc.
828 - 1130 West Pender Street
Vancouver, BC
V6E 4A4

Attention: Michael Walsh

Dear Sir:

Re: This Province's Utility Capital Budgets and Regulatory Approvals

This is further to our discussion and previous correspondence of last week.

The scope we are seeking relates to the filings of regulated utilities and their annual CAPEX budgets which require regulatory approval. Are there are differentiations re the standards for capital budgets for distribution utilities, as compared to utilities whose focus is generation?

Specifically, how do regulatory regimes elsewhere (1) ensure the assets proposed for refurbishment/replacement are appropriately prioritized and included in the CAPEX list in the first place; and (2) ensure that the investments will achieve the expected results (e.g., improved customer service and reliability and reduced operating and maintenance costs).

In particular, how are management practices used to (1) quantify improvements in customer service and reliability and cost savings in operation and maintenance costs resulting from a capital project and (2) quantify the risk of not proceeding with a capital project?

What is the function of SAIDI/SAIFI in the regulator's analysis of the annual CAPEX budget? When will SAIDI/SAIFI objectives be realized or accomplished?

The work will include examples of how the above issues are addressed in other jurisdictions (particularly Ontario, Manitoba and BC, but potentially others, including U.S. states) and measured and reported.

Ratepayers need to find the ways and means to ensure reasonable and cost-effective CAPEX expenditures. Alternative mechanisms, particularly the so-called “capital budget envelope”, should be addressed as a potentially useful and feasible way forward. How is the capital budget envelope implemented and applied in other jurisdictions, with practical examples?

The opinion should consider both rate of return and performance-based regulatory jurisdictions. Comparative legislation or regulations in other jurisdictions with that of this province would be relevant. Finally, you should be aware that once this report is filed it can be subject to requests for information, or, if there was a hearing, oral testimony.

A cost estimate is required to ensure our own budgetary compliance.

We look forward to hearing from you.

Yours truly,

Dennis Browne, KC
Consumer Advocate

/bb

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