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July 29, 2021

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

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

Dear Ms. Blundon:

Re: Supply Cost Accounting Application

Enclosed is Newfoundland and Labrador Hydro's ("Hydro") application for approval of deferral account proposals to address material changes in system costs associated with the integration of the Muskrat Falls Project ("Project") assets to the provincial electricity system.

Under the current Project schedule, as well as the terms of payment associated with the Project agreements, Hydro expects to commence Project payments in October 2021 and is anticipating financial losses in 2021 and potentially 2022, as a result. To mitigate this impact, as well as to deal with changes in supply cost for the provincial system, Hydro is proposing the creation of a new Supply Cost Variance Deferral Account and the discontinuance of the existing Rate Stabilization Plan and its other supply cost deferral accounts. The proposed Supply Cost Variance Deferral Account will also provide a mechanism to deal with rate mitigation funding and/or rate changes implemented solely to recover Project costs.

This application also proposes deviation from International Financial Reporting Standards with respect to expense recognition of Project costs as well as the establishment of a deferral account to address accelerated depreciation costs associated with the Holyrood Thermal Generating Station.

The proposed changes outlined in Hydro's application will enable Hydro's next General Rate Application to proceed in an orderly manner and enable the development of a long-term plan for establishment of customer rates to provide recovery of Project costs, net of rate mitigation funding that may be made available.

The July 28, 2021 announcement by the provincial and federal governments with respect to a financial restructuring plan for the Project does not change the timeline for Project commissioning or the requirement for Hydro to begin making payments under the Project agreements as commissioning proceeds. While the implementation of the announced financial restructuring later in 2021 would reduce the amount of payments required from Hydro, this would not require a modification of any of Hydro's proposals detailed in the attached application.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd

Encl.

ecc: **Board of Commissioners of Public Utilities**
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Supply Cost Accounting Application

July 29, 2021

newfoundland labrador hydro

An application to the Board of Commissioners of Public Utilities

IN THE MATTER OF the *Electrical Power Control Act,* SNL 1994, Chapter E-5.1 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the "*Act*"), and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") pursuant to Section 58, 71, and 80 of the *Act*, for the approval of deferral accounts to address material changes in system costs as a result of the Muskrat Falls Project ("Project") and the phasing out of the Holyrood Thermal Generating Station ("Holyrood TGS") as a generating facility.

To: The Board of Commissioners of Public Utilities ("Board")

THE APPLICATION OF HYDRO STATES THAT:

A. General

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*, is a public utility within the meaning of the *Act*, and is subject to the provisions of the *EPCA*.

2. Under the *Act*, the Board has the general supervision of public utilities and requires that a public utility submit for the approval of the Board the rates, tolls, and charges for the service provided by the public utility and the rules and regulations which relate to that service.

3. The Project will result in a major change in the source of supply of electricity to the island of Newfoundland. Two main contracts provide for the recovery of the Project costs from Hydro: (i) the Muskrat Falls Power Purchase Agreement ("Muskrat Falls PPA") between Hydro and the Muskrat Falls Corporation; and (ii) the Transmission Funding Agreement ("TFA") between Hydro, the Labrador-Island Link Limited Partnership and the Labrador-Island Link Operating Corporation.

4. The Muskrat Falls PPA requires Hydro to pay for the costs of the Muskrat Falls generating facilities and the Labrador Transmission Assets ("LTA"). Monthly payments are required to begin when both these assets are commissioned. The LTA is already commissioned and the current

schedule for the final commissioning of the Muskrat Falls generation assets project has a September 30, 2021 commissioning date.

5. The TFA requires Hydro to pay for the costs of the Labrador-Island Link ("LIL"). Hydro is required to make payments under the TFA beginning one day after full Project commissioning. Order in Council OC2013-343 requires the full Project to be commissioned or nearing commissioning before Hydro can be permitted to recover Project costs through customer rates. Full Project commissioning is currently projected to be November 15, 2021; however, due to delays with the Final Bipole Software, there remains uncertainty on the timing of when Hydro will be required to make TFA payments.

6. The contractual requirement in the Muskrat Falls PPA for Hydro to make payments for the costs of the generating facilities and the LTA is independent of the TFA and its requirement for Hydro to pay for the costs of the LIL. As there is some difference in the potential commissioning dates of the LTA/generating facilities and that of the LIL, based on the current schedule, Hydro may have to begin its payments under the Muskrat Falls PPA before the LIL is commissioned and before Hydro can recover Project costs from customers.

7. Order in Council OC2013-343 requires that any expenditures, payments or compensation paid directly or indirectly by Hydro under an agreement or arrangement to which the Muskrat Falls Exemption Order applies, shall be included as costs in Hydro's cost of service, without disallowance, to be recovered through Island Interconnected System customer rates.

B. Financial Reporting of Supply Costs

8. Since 1986, Hydro has maintained the Rate Stabilization Plan ("RSP") to smooth rate impacts for certain variations between Hydro's test year cost of service estimates for hydraulic production, fuel costs, customer load and rural rates on the Island Interconnected System and actual results. The RSP includes a component to reflect the difference between projected fuel prices and test year values. The current version of the RSP was approved by the Board in Order No. P.U. 30(2019).

9. As an outcome of Hydro's 2013 Amended General Rate Application ("GRA"), in Order No. P.U. 22(2017), the Board approved the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral

Account. These deferral accounts provide for the deferral of variances from Hydro's test year forecast of supply-related costs including, but not limited to, power purchases and gas turbine and diesel fuel costs. The Energy Supply Cost Variance Deferral Account was revised to also include other supply cost variances, the most material item being supply cost variability as a result of purchases of off-island energy over the LIL and the Maritime Link. The current version of the Revised Energy Supply Cost Variance Deferral Account was approved in Order No. P.U. 1(2021).

10. Neither Hydro's RSP nor its other existing supply cost deferral accounts enable Hydro to defer Project costs for future recovery from customers.

11. For regulatory reporting purposes, Hydro adopted International Financial Reporting Standards ("IFRS") as of January 1, 2014, as approved in Board Order No. P.U. 13(2012). Hydro also elected to adopt IFRS 14 — *Regulatory Deferral Accounts* in its initial adoption of IFRS and subsequent financial statements*,* which permits Hydro to continue to account for regulatory deferral account balances in accordance with Canadian Generally Accepted Accounting Principles. The adoption of IFRS 14 – *Regulatory Deferral Accounts* resulted in changes for financial statement presentation purposes only; there was no impact on ratepayers.

12. Hydro has determined that, due to IFRS accounting standards, it will be required to recognize power purchase expenses in a manner that is different from the commercial terms of the Project agreements during both the delivery of pre-commissioning energy and after full commissioning.

13. In Order No. P.U. 9(2021), the Board approved Hydro's proposal to deviate from IFRS, using IFRS 14 – *Regulatory Deferral Accounts*, allowing Hydro to recognize the power purchase costs relating to the delivery of pre-commissioning energy in accordance with the commercial terms of the Muskrat Falls PPA and thereby enable the displacement of more expensive thermal generation to the benefit of Island Interconnected System customers.

14. In Order No. P.U. 15(2020), the Board approved Hydro's request to delay the filing of its GRA as Hydro lacked critical information needed to develop proposed customer rates. The Board directed Hydro to file quarterly updates with respect to the filing of its next GRA beginning on September 30, 2020.

15. As indicated in its most recent GRA update filed on June 30, 2021, Hydro is still awaiting information on the financial restructuring of the Muskrat Falls PPA and the completion of government's rate mitigation plan and therefore does not have adequate information to file a fully informed GRA. Hydro remains uncertain on when it can file its GRA to enable the setting of customer rates in response to the projected costs it will incur under the Muskrat Falls PPA and the TFA.

16. Given the current terms and conditions of the Muskrat Falls PPA, as well as the uncertainty of when Hydro will have the necessary information to file its GRA, Hydro's 2021 financial performance has the potential to be materially impacted by the requirement to commence payments upon the commissioning of the Muskrat Falls generation assets.

C. Changes in Island Interconnected System Supply Costs

17. As discussed in Section 5 of Schedule 1 to this application, changes in power purchases, hydraulic production, or customer load variability will no longer automatically impact the cost of Holyrood TGS fuel incurred by Hydro but instead will impact the amount of energy available to export. As a result, the marginal energy supply cost will change from the high cost of No. 6 fuel at the Holyrood TGS to a relatively low opportunity cost based on the market value of exports.

18. Under the Project agreements, Hydro's monthly payments for energy purchases are effectively fixed monthly charges and may not vary as a result of changes in customer energy requirements. To properly reflect supply cost variations in Hydro's deferral accounts, it is necessary to discontinue the presumption of No. 6 fuel cost variability as a result of load and supply source variability in computing the transfers to the RSP and its other supply cost deferral accounts.

D. Application: Recovery of Supply Cost Variances

19. Hydro is proposing to replace the RSP, the Revised Energy Supply Cost Variance Deferral Account, the Isolated Systems Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account, with the Supply Cost Variance Deferral Account to become effective on the date upon which Hydro is first required to begin payments under the Muskrat Falls PPA ("Implementation Date").

20. Section 6 of Schedule 1 to this application details the components of the proposed Supply Cost Variance Deferral Account.

21. The proposed Supply Cost Variance Deferral Account permits the deferral of costs to Hydro under the Project agreements and provides for savings in No. 6 fuel to be applied to partially offset the deferred Project costs. The proposed account definition of the Supply Cost Variance Deferral Account also enables the crediting of rate mitigation funding and/or billings through customer rates for recovery of Project costs to reduce the balance owing from customers as detailed in Schedule 1 to this application.

22. The proposed Supply Cost Variance Deferral Account also provides for the crediting, to the benefit of customers, of savings that result from Hydro exports (including transmission tariff revenues) and the sale of performance credits resulting from decreased greenhouse gas emissions from the Holyrood TGS.

23. The proposed Supply Cost Variance Deferral Account provides for the transfer of the balances in the RSP and the other supply cost deferral accounts to the proposed deferral account effective as of the Implementation Date. Hydro proposes that, for 2022, the customer rate updates currently required under the RSP (scheduled for January for Island Industrial customers and July for Newfoundland Power Inc.) will proceed and reflect the discontinuance of the fuel riders and the recovery of the remaining current plan balances.

24. Hydro's proposal on the Revised Energy Supply Cost Variance Deferral Account is to transfer the balance to the Supply Cost Variance Deferral Account and transfer the computation of this component into the Supply Cost Variance Deferral Account reflecting the removal of the impact of No. 6 fuel cost variations which no longer reflect system cost dynamics.

25. Hydro is uncertain when rate mitigation will be available to offset the costs that would be deferred in the proposed Supply Cost Variance Deferral Account. Without knowing the magnitude of the amounts to be recovered from customers, Hydro is not yet prepared to propose a recovery period for the deferred costs. Hydro also believes it is appropriate to know the amount of costs deferred in the proposed deferral account prior to proposing an allocation and recovery approach among customer classes.

26. For components of the proposed Supply Cost Variance Deferral Account strictly related to Hydro Rural cost recovery, the *EPCA* requires that these costs not be recovered from Industrial customers. The proposed Supply Cost Variance Deferral Account will continue to exclude allocation to Industrial customers in accordance with the legislation.

27. In its next GRA, Hydro will provide additional evidence on a long-term approach to the Supply Cost Variance Deferral Account to provide an opportunity for recovery of supply cost variances from those reflected in customer rates (including Project costs).

28. Hydro plans to file a separate application to deal with the balance allocation and disposition in the proposed Supply Cost Variance Deferral Account after conclusion of its next GRA.

29. Hydro proposes to use its approved test year weighted average cost of capital in determining the finance costs to apply in computing the deferral account balance. This proposed approach is consistent with the current requirement of the RSP.

30. Schedule 1, Appendix A provides the proposed Supply Cost Variance Deferral Account definition.

31. Approval of the proposed Supply Cost Variance Deferral Account would:

(i) Enable Hydro to defer the net increase in costs incurred by Hydro as a result of the Project until rate mitigation is provided by government or a cost recovery plan can be established for future recovery from customers;

(ii) Modify the existing approach to computing supply cost variances so that the transfers to the proposed Supply Cost Variance Deferral Account will be reflective of the changes in future supply cost variability on the Island Interconnected System; and

(iii) Be consistent with legislation in that it will provide Hydro the opportunity for recovery of Project charges in the future.

E. Application: Recovery of Holyrood TGS Accelerated Depreciation

32. As discussed in Section 7 of Schedule 1 to this application, Hydro is projecting a material increase in depreciation expense (>$15 million) for the Holyrood TGS in 2022 as a result of the

use of accelerated depreciation and the projected end of generation date of March 31, 2023. The projected increase in accelerated depreciation is not reflected in existing customer rates.

33. Hydro is proposing the creation of the Holyrood TGS Accelerated Depreciation Deferral Account to defer the difference between the actual accelerated depreciation at the Holyrood TGS in 2022 and the approved 2019 Test Year costs. Schedule 1, Appendix B provides the proposed definition for this account.

34. Hydro anticipates that its next GRA is not likely to conclude before 2023. The proposed approach would avoid negative impacts on Hydro's 2022 earnings as a result of prudently incurred investments in the Holyrood TGS to provide reliable service to customers.

F. Application: Financial Reporting of Project Costs

35. As discussed further in Section 8 of Schedule 1 to this application, Hydro is proposing to deviate from IFRS, using IFRS 14 – *Regulatory Deferral Accounts*, which would allow Hydro to recognize the power purchase costs relating to the delivery of post-commissioning energy in accordance with the commercial terms of the Muskrat Falls PPA and the TFA.

36. The proposed approach would avoid non-cash accounting expenses associated with the Project agreements to have impacts on Hydro's revenue requirement and/or net income.

37. The proposed accounting deviation would have no impact on customers. In addition, the treatment will be consistent with Hydro's past regulatory accounting practices of recognizing purchase power expenses in accordance with the payment terms of the agreements (e.g., Exploits Power Purchase Agreement, capacity assistance agreements, wind purchase agreements, etc.) and the pre-commissioning IFRS Deviation approved in Board Order No. P.U. 9(2021).

38. The Muskrat Falls PPA requires Hydro to make capital contributions to fund sustaining capital for the Muskrat Falls generating assets and the LTA. These capital contributions are treated as operating and maintenance costs under the Muskrat Falls PPA. Recognition of sustaining capital as operating costs is not consistent with the regulatory principles of intergenerational equity or rate stability.

39. Hydro proposes to establish the Muskrat Falls PPA Sustaining Capital Deferral Account to defer the contributions required by Hydro for sustaining capital investments in accordance with the Muskrat Falls PPA. Upon payment of sustaining capital costs, Hydro would defer these costs with the recovery approach to be determined in Hydro's next GRA. Schedule 1, Appendix C provides the proposed definition for this account.

40. Approval of the proposed Muskrat Falls PPA Sustaining Capital Deferral Account would provide time for regulatory process to proceed in determining the appropriate approach for recovery of Hydro's costs of funding sustaining capital investments for the Muskrat Falls generating facility and the LTA.

G. Hydro's Requests

41. Hydro requests the Board approve:

(i) The proposed Supply Cost Variance Deferral Account, for which the account definition is provided in Schedule 1, Appendix A, to become effective on the date upon which Hydro is required to begin payments under the Muskrat Falls PPA;

(ii) The proposed discontinuance of the: RSP; Revised Energy Supply Cost Variance Deferral Account; Isolated Systems Supply Cost Variance Deferral Account; and the Holyrood Conversion Rate Deferral Account to occur on the date of the implementation of the Supply Cost Variance Deferral Account;

(iii) The proposed Holyrood TGS Accelerated Depreciation Deferral Account, for which the account definition is provided in Schedule 1, Appendix B, to become effective January 1, 2022;

(iv) The proposal to deviate from IFRS, using IFRS 14 – *Regulatory Deferral Accounts*, which would allow Hydro to recognize the power purchase costs relating to the delivery of post-commissioning energy in accordance with the commercial terms of the Muskrat Falls PPA and the TFA; and

(v) The proposed Muskrat Falls PPA Sustaining Capital Deferral Account, for which the account definition is provided in Schedule 1, Appendix C.

H. Communications

42. Communications with respect to this application should be forwarded to Shirley A. Walsh, Senior Legal Counsel, Regulatory for Hydro.

DATED at St. John's in the Province of Newfoundland and Labrador this 29th day of July 2021.

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Counsel for the Applicant
Newfoundland and Labrador Hydro,
500 Columbus Drive, P.O. Box 12400
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Schedule 1

Evidence

Contents

List of Appendices

1.0 Introduction

The commissioning of the Muskrat Falls Project ("Project") and the subsequent interconnection of the Island Interconnected System with Labrador by way of the Labrador-Island Link ("LIL"), and the North American grid by way of the Maritime Link will result in a major change in the source of supply of electricity to the island of Newfoundland. Two main contracts provide for the recovery of the Project costs from Newfoundland and Labrador Hydro ("Hydro"): (i) the Muskrat Falls Power Purchase Agreement ("Muskrat Falls PPA") between Hydro and the Muskrat Falls Corporation; and (ii) the Transmission Funding Agreement ("TFA") between Hydro, the Labrador-Island Link Limited Partnership and the Labrador-Island Link Operating Corporation.

Upon the commissioning of the Project, currently projected to occur later in 2021, supply cost payments will commence under the Muskrat Falls PPA and the TFA, and the Holyrood Thermal Generating Station ("Holyrood TGS") is expected to be phased-out as a generating facility.[1] Under the current Project schedule, the Muskrat Falls PPA will be implemented in early October and the TFA will be implemented in mid-November. Hydro anticipates there may be a delay between when Hydro is required to begin making payments under the Project agreements and when rate mitigation and/or recovery through customer rates will occur.[2]

1.1 Recent Rate Mitigation Announcement

On July 28, 2021, the provincial and federal governments announced an agreement in principle on a financial restructuring plan for the Project. The objective of the agreement is to reduce the customer rate impacts resulting from the Project. The announcement does not change the timeline for Project commissioning or the requirement for Hydro to begin making payments under the Project agreements as commissioning proceeds.

While the implementation of the announced financial restructuring later in 2021 would reduce the amount of payments required from Hydro, this implementation would not require a modification of any of the proposals presented in this evidence and requested for approval in Hydro's Supply Cost Accounting Application ("Application"). As the announcement on July 28, 2021 is an agreement in

[1] Holyrood TGS will function as a fully capable standby facility during the early years of operation of the Muskrat Falls Hydroelectric Generating Station and the LIL. Thereafter, the Holyrood TGS facility is planned to be used as a synchronous condenser.
[2] As per the direction provided in OC2013-343.

principle, the estimated Project cost estimates presented in this evidence reflect the existing Project agreements.

1.2 Application

Due to the change in Island Interconnected System supply costs as well as the potential for incurrence of Project costs in advance of Hydro's ability to recover, Hydro must revise its supply cost deferral accounts to ensure the transfers to its supply cost deferral accounts will reflect the system cost variances that will occur from that point forward.[3] The planned end of generation at the Holyrood TGS as of March 31, 2023 is contributing to a material increase in depreciation expense in 2022. The Application proposes a deferral account to defer the 2022 projected increase in Holyrood TGS accelerated depreciation until a proposal for recovery is dealt with in Hydro's next GRA. It will also be necessary to deviate from International Financial Reporting Standards ("IFRS"), using IFRS-14 – *Regulatory Deferral Accounts*, to permit recognition of purchase power costs consistent with regulatory accounting principles.

The proposed Supply Cost Variance Deferral Account proposed in the Application presents proposals to enable a deferral account to deal with Hydro being required to make payments under the Project agreements prior to having the opportunity to recover the costs. Hydro is also projecting an annual increase in Project costs combined with minimal load growth. These two attributes will contribute to a revenue deficiency between test years unless a deferral account is implemented to provide the opportunity for recovery of the increasing Project costs. The proposed deferral account would also provide for rate mitigation funding and/or rate changes implemented solely to recover Project costs to be applied to the proposed deferral account to offset Project charges to Hydro. The proposed approach would effectively isolate the net effect of the Project costs and rate mitigation (and/or Project related rate increases) in a deferral account and enable Hydro's next GRA to proceed in an orderly manner to enable the development of a long-term plan for establishment of customer rates to provide recovery of Project costs, net of rate mitigation funding that may be made available.

[3] A review on the anticipated changes to its supply cost recovery mechanisms was filed by Hydro on June 15, 2016 in accordance with the Settlement Agreements to the 2013 General Rate Application ("GRA"). In that report, Hydro indicated it will file, prior to filing its next GRA, the proposed supply cost deferral accounts and recovery mechanisms that are required to permit Hydro to recover supply cost payments resulting from the commissioning of the Project assets.

The proposed Supply Cost Variance Deferral Account will also replace the Rate Stabilization Plan ("RSP") and Hydro's other supply cost deferral accounts. The proposed deferral account described in this evidence and reflected in Hydro's Application will serve to enable deferral of material supply cost variances from those reflected in current rates until the conclusion of Hydro's next GRA. Hydro is proposing that the Supply Cost Variance Deferral Account become effective in the month when payments are initiated under the Muskrat Falls PPA.

In its next GRA, Hydro will provide additional evidence on a long-term approach to the Supply Cost Variance Deferral Account which will include a proposed allocation and recovery approach to the deferral account balances that will accumulate subsequent to Project costs and rate mitigation being reflected in customer rates. Hydro proposes to file a future application with the Board of Commissioners of Public Utilities ("Board"), subsequent to the next GRA Order, to deal with allocation and recovery of the balance in the Supply Cost Variance Deferral Account that accumulates prior to the conclusion of the next GRA.

This evidence details and supports the proposals in Hydro's Application. The evidence includes:

- A background of Hydro's existing supply cost deferral accounts;
- Information on the legislative and government policy provisions intended to ensure Project cost recovery;
- A summary of the Project agreements and the impacts on the Island Interconnected System supply costs;
- A description of the proposed Supply Cost Variance Deferral Account;
- The requirement for a deferral account to deal with a material increase in accelerated depreciation for the Holyrood TGS;
- The requirement for a deviation from IFRS in the recognition of purchase power expense associated with charges under the Project agreements; and
- The requirement for the use of a deferral account in the treatment of charges to Hydro under the Muskrat Falls PPA for sustaining capital associated with the Muskrat Falls generating assets and the Labrador Transmission Assets ("LTA").

2.0 Existing Supply Cost Deferral Accounts

Prior to the commissioning of the Project, fuel costs required to operate the Holyrood TGS have comprised the largest single portion of the supply costs incurred by Hydro. Due to the potential volatility of Holyrood TGS fuel costs, Hydro has maintained the RSP since 1986 to stabilize customer rates from monthly variations in Holyrood TGS fuel costs due to price variances, volume variances, and load variations. The purpose of the RSP is to ensure that rates reasonably recover Holyrood No. 6 fuel costs and moderate customer bill variability between test years. Project commissioning is expected to result in the eventual discontinuance of the use of No. 6 fuel at the Holyrood TGS. Even if the Holyrood TGS is required to continue to operate as a standby generating facility, the RSP structure still needs to be revised as No. 6 fuel will no longer reflect the marginal energy cost on the Island Interconnected System and, therefore, material modifications are required to reflect the change in system marginal energy costs.

In Board Order No. P.U. 22(2017), the Board approved the definitions for three new supply cost deferral accounts: (i) the Isolated Systems Supply Cost Variance Deferral Account; (ii) the Energy Supply Cost Variance Deferral Account; and (iii) the Holyrood Conversion Rate Deferral Account. In 2019, the Board approved the Revised Energy Supply Cost Variance Deferral Account[4] to include variances of price and volume from off-island power purchases.[5]

Hydro's supply costs deferral accounts were structured to deal with volatility in the marginal energy cost on the Island Interconnected System. The Revised Energy Supply Cost Variance Deferral Account also operates on the premise that Holyrood TGS is the marginal generating source on the Island Interconnected System. With No. 6 fuel as the marginal energy cost on the Island Interconnected System, actual costs (due to changes in supply source, fuel price, or load variability) could change materially from the test year costs that were the basis for establishing customer rates.

The transition to energy supply being provided by the Project will create a material shift in Island Interconnected System cost attributes and introduces new risks for Hydro with respect to recovering its supply costs.

[4] The Revised Energy Supply Cost Variance Deferral Account was approved in Board Order No. P.U. 30(2019).
[5] Effective January 1, 2021, the Board approved Firm Energy Power Purchases from Corner Brook Pulp and Paper Limited ("CBPP") for inclusion in the Revised Energy Supply Cost Variance Deferral Account per Board Order No. P.U. 1(2021).

3.0 Government Policy and Legislation

3.1 Legislation

Government has established a legislative framework which is relevant when dealing with proposals by Hydro to enable it to achieve supply cost recovery and, specifically, recovery of Project costs. Subsection 80(2) of the *Public Utilities Act* permits a public utility to recover those operating expenses that the Board may allow as prudently incurred in providing electrical service. Supply costs such as power purchases and fuel costs are generally considered prudent and included in setting customer rates. Actual supply costs often vary from forecasted costs for reasons beyond the control of the utility. Permitting recovery of supply cost variances from the approved supply costs reflected in customer rates through deferral mechanisms is common practice in regulatory jurisdictions across Canada.[6]

With respect to Project costs, the government provided specific direction on supply cost recovery. In Order in Council OC2013-343, the government set forth the requirement that any expenditures, payments or compensation paid directly or indirectly by Hydro under an agreement or arrangement to which the Muskrat Falls Exemption Order applies, shall be included as costs in Hydro's cost of service, without disallowance, to be recovered through Island Interconnected System customer rates. Through the Muskrat Falls PPA and the TFA this includes costs related to the Muskrat Falls generation assets, LIL assets, and the LTA.

In order for Hydro to fully recover annual costs resulting from charges related to the Project, it is necessary for Hydro to maintain a supply cost recovery mechanism to allow recovery of cost variances relative to the Project costs included in approved test year rates.

3.2 Rate Mitigation

Setting customer rates to recover the full cost of the Project will require residential rates to increase by approximately 70% in 2022 (i.e., from 13.4 cents per kWh to 22.7 cents per kWh) and Island Industrial rates to increase by approximately 90% (from 6.2 cents per kWh to 11.8 cents per kWh).[7] For the residential rate not to exceed 13.5 cents per kWh for 2022, rate mitigation funding of approximately

[6] See Response to Request for information PUB-NLH-388 of Hydro's 2013 GRA.
[7] Derived based on Project cost estimates as of December 2020 and existing terms of Muskrat Falls PPA and TFA.

$585 million will be required to be provided.[8] This estimate assumes no change in the existing Muskrat Falls PPA structure and that rate mitigation will be provided to all customers on the Island Interconnected System.

The final financial structure chosen for the Muskrat Falls PPA will dictate the level of rate mitigation required annually. While the amount can vary materially depending on the financial structure, it is anticipated that a significant level of rate mitigation funding will be required for many years.[9] As such, a formalized mechanism to incorporate rate mitigation into the regulatory process for setting customer rates is appropriate. The formalized mechanism could be through a billing credit or the use of a deferral account.[10]

4.0 Overview of Project Agreements

4.1 Muskrat Falls PPA

The financial structure of the Muskrat Falls PPA reflects a payment schedule which escalates annually at a rate of 2%. The agreement provides for recovery of the costs of the Muskrat Falls generating facilities and the LTA. The LTA are the transmission facilities of the Project that are being constructed by Labrador Transmission Corporation to interconnect the Muskrat Falls generation assets with the grid.

The initial Muskrat Falls generation capital costs are collected by way of Base Block Capital Costs Recovery payments through the Muskrat Falls PPA.[11] These payment amounts do not provide for the recovery of operation and maintenance ("O&M") costs or the investment required for sustaining capital for the assets over the 50-year supply period reflected in the contract.[12] The Muskrat Falls PPA requires Hydro to contribute the funding for the sustaining capital costs for the Muskrat Falls generating facility and the LTA as these costs are not reflected in the Base Block Capital Costs Recovery amounts.

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[8] Approximately $65 million will be required for each 1 cent per kWh of rate mitigation provided to Domestic customers. This includes approximately $7 million per 1 cent per kWh of rate mitigation to be provided to Island Industrial customers.

[9] Under the existing financial structure of the Muskrat Falls PPA, rate mitigation funding could be required for the full 50 years of the contract.

[10] Hydro is currently uncertain of the details and the timing of implementation of government's rate mitigation plan.

[11] The required payment amounts by year are provided in Schedule 1 of the Muskrat Falls PPA and provide for the recovery of the original cost of the Muskrat Falls generation assets.

[12] Schedule 1 of the Muskrat Falls PPA will be updated to reflect the costs as of the in-service date of the Muskrat Falls Project. The Generation Interconnection Agreement ("GIA") also includes a Schedule 1 providing the original capital cost recovery schedule for charges from LTA to Muskrat Falls Corporation for the LTA. The GIA, Schedule 1 will also be updated to reflect new cost information.

Schedule 2 to the Muskrat Falls PPA provides the forecast of customer load requirements on the Island ("NL Native Load")[13] and the forecast load requirements from Muskrat Falls generation for each operating year of the contract to serve the NL Native load ("Base Block Energy"). If Hydro's customer load requirements on the Island Interconnected System in an operating year require Hydro's purchases from Muskrat Falls Corporation to exceed the Base Block Energy and Muskrat Falls Corporation has the additional amount of energy available (i.e., available Supplemental Block Energy[14]), Hydro is not required to pay additional charges for the increased purchases to supply customer load.[15] Similarly, if reduced customer load requirements result in Hydro's purchases being lower than the Base Block Energy in the operating year, Hydro's required payment amounts under the Muskrat Falls PPA are not reduced for the operating year.

In addition to the original capital cost recovery described above, the Muskrat Falls Corporation will estimate and bill a separate monthly charge to Hydro, with quarterly true ups to actual, to recover the O&M Costs, including the cost of sustaining capital for Muskrat Falls generation. These costs will be recovered through a charge to Hydro for O&M Costs.[16] Charges to Hydro for O&M Costs also include other costs incurred by Muskrat Falls Corporation such as: payments pursuant to the impact and benefit agreements; payments pursuant to the water lease; payments pursuant to the Water Management Agreement; and administrative costs and taxes.[17] The LTA payments made by Muskrat Falls Corporation to Labrador Transmission Corporation, which include LTA capital cost recovery and costs associated with LTA O&M Activities as well as LTA Sustaining Capital, are included in the O&M Costs charged to Hydro in the Muskrat Falls PPA.[18]

4.1.1 Fixed vs. Variable Costs

Should Hydro require less supply from Muskrat Falls generation to serve its customers than is designated for Hydro in Schedule 2 of the Muskrat Falls PPA, there is no reduction in the payments required of Hydro. However, in this circumstance the excess Schedule 2 energy can be exported by Hydro to provide value to its customers.

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[13] A definition of NL Native Load is provided on page 14 and Schedule 2 of the Muskrat Falls PPA.

[14] The Supplemental Block Energy represents the amount by which the actual NL Native Load in any operating year exceeds the Initial Load Forecast as defined in the Muskrat Falls PPA.

[15] This assumes no change in Hydro's energy supply from the forecast reflected in Schedule 2 to the Muskrat Falls PPA.

[16] The complete description of O&M Costs is provided on page 15 of 76 of the Muskrat Falls PPA.

[17] Ibid.

[18] See Section 8.1(b) of the GIA between Hydro (in its capacity as the system operator) and Muskrat Falls Corporation and Labrador Transmission Corporation.

Hydro's current forecast load requirements from Muskrat Falls generation are less than its contracted entitlement provided in Schedule 2 of the Muskrat Falls PPA. This provides the opportunity for this excess energy to be exported. Export revenue benefits may also accrue to Hydro's customers from other external market activities such as ponding.

In general, customer load growth in the short term does not increase the payments required under the Muskrat Falls PPA, but increased customer load will decrease the excess schedule energy available for export. If, in future, the full Muskrat Falls generation is being utilized and no Supplemental Block Energy is available, customer load growth could require additional purchase costs to be incurred by Hydro based on market rates. If Hydro requires more Muskrat Falls generation than provided for in Schedule 2 due to reduced energy generation being available to Hydro from other sources (i.e., total of self-generation, power purchases, and customer-owned generation), Hydro can incur additional purchased power costs based on market rates.[19]

The Muskrat Falls PPA provides the option for Hydro to defer excess energy in the current year and borrow excess energy from future years (if available) to avoid incurring additional power purchase costs in circumstances when reduced Island energy generation may be available (for example, low hydrology on the Island). To defer excess Schedule 2 energy would require Hydro to declare that it will defer excess energy rather than monetizing its excess as export revenues.

4.2 Transmission Funding Agreement

The TFA recovers costs associated with the LIL facilities through payments by Hydro to the Labrador-Island Link Operating Corporation, the LIL operating entity. The payments to Labrador-Island Link Operating Corporation are based on a return on rate base approach in which the annual cost recovery amount is based on return on equity plus O&M costs, depreciation and taxes.

Cost recovery in the TFA is higher in the early years of the service period, reflecting high early levels of return due to the higher net book value of the plant. As the assets age and the net book value declines, the annual cost recovery declines. The return on equity in the TFA will reflect the approved return on

[19] Assumed annual generation at CBPP is 880.1 GWh and Newfoundland Power Inc. ("Newfoundland Power") is 437 GWh. These amounts are included in the NL Native Load Forecast in Schedule 2 of the Muskrat Falls PPA. The Base Block Energy was determined based on Hydro's Island Interconnected System energy supply and power purchase forecast carried forward for the term of the Muskrat Falls PPA in consideration of Island Interconnected System forecast energy growth requirements and expiry of contracted power purchases from the CBPP cogeneration facility and the wind generation facilities in St. Lawrence and Fermeuse. See footnotes on page 2 of 2, Schedule 2 to Muskrat Falls PPA.

equity for Newfoundland Power. As a result, changes in the allowed return on equity for Newfoundland Power will require a change in the annual cost recovery amount in the TFA.

Unlike the Muskrat Falls PPA, Hydro is not required under the TFA to finance sustaining capital through capital contributions. Hydro will pay for sustaining capital under the TFA through its monthly bill payments which will include depreciation and financing costs associated with the sustaining capital.

5.0 Project Impacts on Island Interconnected System Supply Costs

5.1 Embedded Supply Costs

Table 1 provides an illustrative comparison of Hydro's average embedded costs for the 2019 Test Year with a high level estimate of cost of supply in 2022 reflecting the inclusion of Project costs upon the first full year of commissioning and the removal of Holyrood TGS generation costs.[20]

Table 1: Average Embedded Costs for the Island Interconnected System (Cents per kWh)

	2019 Test Year	Projected 2022 Costs	Difference
Newfoundland Power (Including Rural Deficit)	8.7	17.4	8.7
Island Industrial	6.1	11.8	5.7

Table 1 demonstrates the material increase in Hydro's unit cost of supplying customers on the Island Interconnected System. This increase in costs will be reflected in the cost of service study in Hydro's next GRA. However, available rate mitigation would be applied in determining the net amount to be recovered from customers.

[20] Project cost estimates reflected in this report reflect the most current information available to Hydro and are presented for illustration purposes. The annual revenue requirements required to recover the costs of the Project from Hydro customers will be updated in Hydro's next GRA filing to reflect any updates to the terms of the Project agreements, the Project schedule, and the cost estimates.

5.2 Marginal Supply Costs

5.2.1 Marginal Energy Costs

While changes in customer load requirements may not impact the monthly charges to Hydro under the Muskrat Falls PPA, customer load variations will impact the amount of Muskrat Falls generation available for export sales.[21] In a scenario in which Hydro is required to access the Supplemental Block Energy to meet customer load requirements, there is reduced Muskrat Falls generation available for export sales. In a scenario in which Hydro purchases less than the Base Block Energy as a result of lower customer load requirements, there is increased Muskrat Falls generation available for export sales. In this scenario, Hydro has the opportunity to either monetize the unused portion of the Base Block Energy based on the value that can be obtained through the export market or defer such energy for future use.[22, 23]

As a result of the structure of the Muskrat Falls PPA, the marginal cost of energy on the Island Interconnected System upon full Project commissioning will change from No. 6 fuel at the Holyrood TGS to the market value of exports upon Project commissioning. This is a material shift from historical system costs which will require modifications to Hydro's supply cost deferral accounts and the wholesale rate design. For example, in the 2019 Test Year, the No. 6 fuel price used as a basis for setting the marginal price to Newfoundland Power was approximately 18 cents per kWh. Illustratively, the forecast net revenues from exports for 2022 is approximately 1 cent per kWh.

During the transition to Project availability, there is uncertainty on when the Final Bipole Software for the LIL will enable delivery of the full 900 MW of capacity to the Island. Until that time, it would be reasonable to assume the marginal cost of energy on the Island Interconnected System as the market value of imports (i.e., the market value of energy plus the cost of transmission to deliver the energy to the Island). This would provide a marginal cost slightly higher than the value of export sales.

[21] There is no explicit provision in legislation requiring the value of export sales by the Muskrat Falls Corporation to be credited back to ratepayers to offset the cost of supply from Muskrat Falls. However, the current government has indicated that export sales will be used to mitigate potential increases in electricity rates. Source: Letter from the Premier to the Minister of Natural Resources dated December 14, 2015.

[22] See Article 3.1(c) on page 25 of 76 of the Muskrat Falls PPA.

[23] The Muskrat Falls PPA requires that transactions between Hydro and Muskrat Falls Corporation will use the Average Annual Sales Price in computing charges for transactions to external markets. See Article 4.5(d), page 34 of 67 of the Muskrat Falls PPA.

5.2.2 Marginal Capacity Costs

Hydro's current assumptions reflect the retirement of the Holyrood TGS, as well as the gas turbines at Hardwoods and Stephenville following the in-service of the Muskrat Falls Hydroelectric Generating Station. The net impact of the planned additions and retirements to capacity for the Island Interconnected System is shown in Table 2.

Table 2: Island Interconnected System Capacity Additions and Retirements

Capacity Addition/Retirement	Capacity Impact (MW)
Muskrat Falls	824
Excess Recapture	72
Total Available on LIL[24]	896
Less: Forecast Losses	(70)
Less: Emera's Entitlement	(158)[25]
Subtotal LIL	668
Holyrood TGS Retirement	(490)
Hardwoods Retirement	(50)
Stephenville Retirement	(50)
Remaining Capacity	78
P90 Adjustment[26]	(60)
Net Change in Capacity	**18**

Table 2 shows the net impact of 78 MW as a result of the capacity additions, offset by capacity retirements. With the adjustment for a P90 forecast for system planning, the additional capacity available in the short-term is further reduced to a net change in capacity of only 18 MW.

Hydro's Reliability and Resource Adequacy Study determined that if capacity additions are required to meet load growth, the capacity additions should be located on the Island.[27] The limited additional generation capacity available from the Project and the fact that future capacity additions should be located on the Island (i.e., rather than firm capacity through imports) contributes to relatively high marginal generation capacity costs. Gas turbines are generally accepted as the least-cost generation option to supply capacity-only requirements.

[24] Combination of recapture energy from Churchill Falls and Muskrat Falls generation.
[25] Firm capacity of the Emera Block as measured at Bottom Brook Terminal Station.
[26] The 60 MW reduction for P90 would be removed if the Board determines in the Resource and Reliability Adequacy Study proceeding that system planning can be based on a P50 load forecast.
[27] Firm transmission is not available to acquire adequate firm capacity for the long term through imports to the Island.

A high marginal capacity cost does not have an immediate impact on the ability of Hydro to recover its supply costs. However, additional generation capacity requirements will further increase the embedded cost of supply for the Island Interconnected System and contribute to higher customer rates in the future.

5.3 Relationship of Marginal Costs to Embedded Costs

Going forward, it is expected that the average embedded cost of supplying customers will materially exceed the marginal energy cost on the Island Interconnected System. This is a reversal of the historical approach on the Island Interconnected System in which the marginal cost of energy (No. 6 fuel at the Holyrood TGS) has recently been materially higher than Hydro's average embedded costs of supplying customers.

With the reversal of the historical embedded cost/marginal cost relationship, changes in revenues resulting from changes in load are expected to materially exceed the changes in Hydro's net revenue from exports. In general, changes in load requirements will not change billings to Hydro under the Project agreements. The transition from Hydro's historical cost of supply being highly variable depending on customer load requirements and hydrology (i.e., impacting fuel cost from Holyrood TGS) to being predominantly a fixed cost can create a material financial risk for Hydro in dealing with revenue variability between test years. Reduced customer load requirements will reduce revenue at a much higher unit rate than the offsetting benefits of increased revenue from export. Aside from decisions about rate structure and pricing, the issue arises as to whether there should be a continuation of a requirement for the financial impact of customer load variations to be dealt with in a supply cost recovery mechanism.[28] This matter will be further discussed in Section 6.

5.4 Project Cost True Ups

Both Project agreements provide for a true up to actual O&M Costs on a quarterly basis.

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[28] This is evident in the pricing structures currently in place for Newfoundland Power and Island Industrial customers. The load variation component of the RSP is currently required to deal with the earnings impacts of load variations of Island Industrial customers because the energy price is derived based on the average embedded cost which is materially lower than the marginal cost (i.e., No. 6 fuel at the Holyrood TGS). However, no load variation component is required to deal with load variations from Newfoundland Power because the end block is priced at the test year Holyrood TGS fuel price.

Chart 1 provides an illustration of the change in Hydro's costs for the period 2022–2031 for the Project assuming full commissioning has been achieved prior to 2022. This chart assumes a total Project construction cost of $10.2 billion plus $2.9 billion in financing costs.[29]

Chart 1 is provided to demonstrate that Hydro's Muskrat Falls supply costs will increase annually after the initial rate change which is required to include Project costs in customer rates. These annual cost changes beyond the Project commissioning reflect the current structure of the Project agreements.[30]

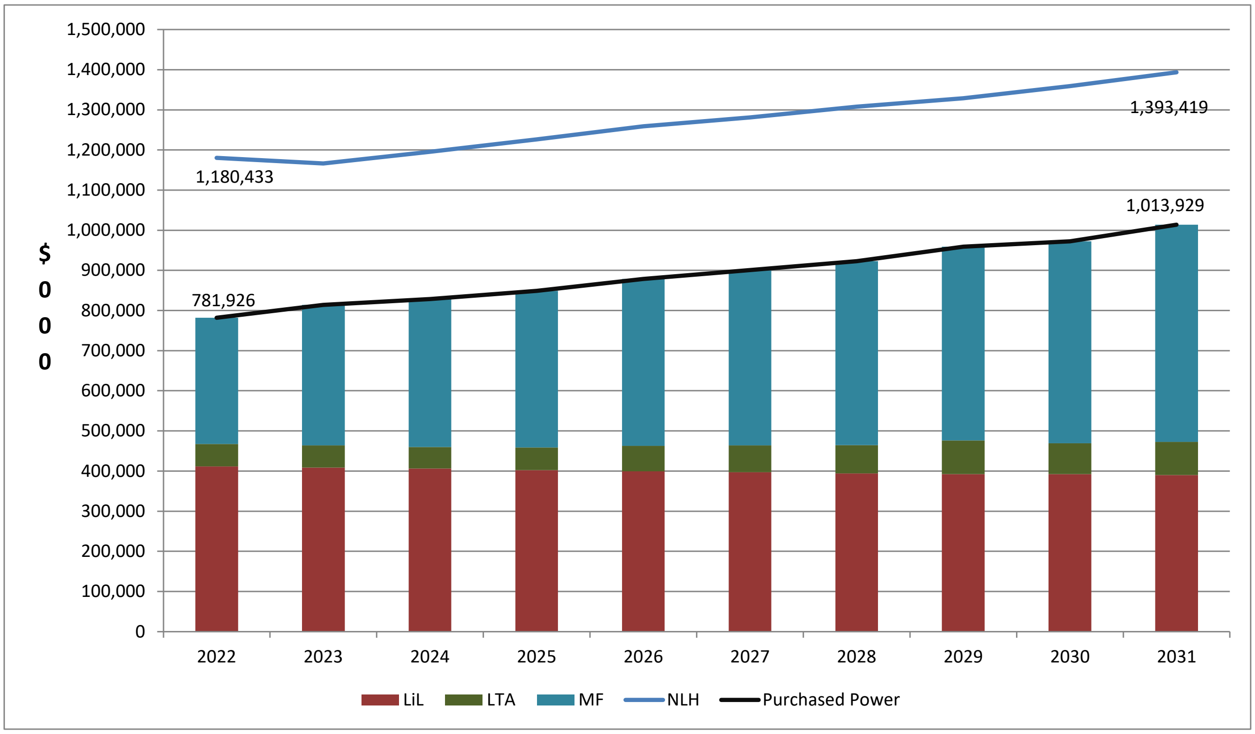

Chart 1: Hydro's Illustrative Costs 2022–2031

Chart 1 shows Hydro's increased annual costs of approximately $21 million per year (approximately 1.8% per year). The increases in charges to Hydro through the Project contracts are related to the project's capital and operating costs and do not vary with customer load requirements.

Hydro is forecasting approximately 3.1% cumulative load growth for the period 2022–2031 (i.e., approximately 0.35% per year). The annual rate of increase in the cost to serve illustrated in Chart 1 exceeds the forecast annual rate of customer growth. Most of the cost increase per year is a result of

[29] The annual revenue requirements required to recover the Project costs will change based on the final costs of the Project.
[30] The forecast annual revenue requirement for Project Costs excludes the required investment for sustaining capital.

the escalating supply cost under the Muskrat Falls PPA. An increase in year-over-year costs combined with minimal load growth will contribute to a revenue deficiency between test years unless a deferral account is implemented to provide recovery of the costs of the Project.

6.0 Proposed Supply Cost Variance Deferral Account

This section describes the Supply Cost Variance Deferral Account proposed to serve as a replacement of the RSP and Hydro's other supply cost deferral accounts. The proposed deferral account will enable deferral of supply cost variances from those reflected in current rates. The proposed deferral account is also structured to enable rate mitigation funding and/or billings from rate increases meant to recover Project costs to apply to reduce the balance owing from customers. Hydro is proposing that the Supply Cost Variance Deferral Account will become effective in the month when the first payment is initiated under the Muskrat Falls PPA.

In its next GRA, Hydro will provide additional evidence on a long-term approach to the Supply Cost Variance Deferral Account that will include a proposed allocation and recovery approach to the deferral account balances that will accumulate subsequent to Project costs and rate mitigation being reflected in customer rates. Thereafter, Hydro proposes to file an application with the Board to deal with allocation and recovery of the supply costs that were deferred prior to the finalization of customer rates reflecting Project costs.

The definition of the proposed Supply Cost Variance Deferral Account is provided in Appendix A to this evidence. The proposed deferral account includes the following components:

(i) Muskrat Falls Project Costs;

(ii) Holyrood TGS Fuel Costs;

(iii) Net Revenues From Exports;

(iv) Transmission Tariff Revenues;

(v) Greenhouse Gas Credit Revenues;

(vi) Other Island Interconnected System Supply Costs Variances;

(vii) Load Variations;

(viii) Rural Rate Adjustments;

(ix) Isolated Systems Supply Cost Variances;

(x) Utility and Industrial Plan Balances; and

(xi) Cost Recovery and Financing Costs.

6.1 Muskrat Falls Project Costs

Commissioning of the LIL is not required in advance of payment obligations pursuant to the Muskrat Falls PPA taking effect, which occurs upon commissioning of the Muskrat Falls generation and the LTA. It is currently projected that Hydro will be required to begin payments under the Muskrat Falls PPA on October 1, 2021, in advance of the full commissioning of the LIL. Hydro is required to begin payments under the TFA one day after full Project commissioning, currently scheduled for November 14, 2021.

The monthly payments for 2021 under the Muskrat Falls PPA and the TFA are projected to be approximately $33 million and $34 million, respectively. The inability to recover a single month of the Muskrat Falls PPA payment would result in Hydro reporting a financial loss for 2021. Therefore, Hydro is proposing the Supply Cost Variance Deferral Account to permit deferral of the Project costs for future recovery. Approval of Hydro’s proposal would be consistent with Order in Council OC2013-343.[31]

The proposed Supply Cost Variance Deferral Account definition provided in Appendix A allows the difference between the actual charges to Hydro under the Project agreements and the charges reflected in approved test year costs to be deferred for future disposition. As the 2019 Test Year did not include any charges from the Project agreements, the full amount of the charges under the Project agreements will initially be charged to the proposed deferral account. However, the proposed deferral account definition also enables the reduction in the balance owing from customers through the crediting of rate mitigation funding and/or billings from increased customer rates intended to recover Project costs.[32]

As explained in Section 5.3, the Project agreements provide for quarterly cost true ups. As Hydro will not have the opportunity to immediately recover changes in Project costs through customer rates, these

[31] OC2013-343 requires the full Project to be commissioned before Hydro can be permitted to recover Project costs through customer rates.

[32] Sections A.2 and A.3 of the proposed Supply Cost Variance Deferral Account provide for separate tracking of any rate mitigation funds provided by government and the amount of Project costs recovered from customers through changes in customer rates. Project costs recovered from customers through increased rates will be tracked by customer class in the deferral account.

changes in costs from cost true ups would be charged or credited to this cost component for future disposition.

6.2 Holyrood TGS Fuel Costs

At this time, the long-term plan for the operation of the Holyrood TGS is for its retirement as a generating facility and the continued use of Unit 3 as a synchronous condenser. As a result, the long-term plan would not reflect any Holyrood fuel costs.

Table 3 provides the 2019 Test Year production and fuel costs on a monthly basis.

Table 3: 2019 Test Year Monthly Fuel Costs

Month	Barrels	Fuel Cost
January	421,132	44,597,879
February	363,087	38,450,913
March	178,662	18,920,306
April	104,889	11,107,745
May	63,808	6,757,267
June	29,297	3,102,552
July	-	-
August	-	-
September	61,750	6,539,325
October	127,616	13,514,534
November	221,887	23,497,833
December	262,852	27,836,027
Total[33]	**1,834,980**	**194,324,382**

If the Holyrood TGS was no longer required to supply generation upon commissioning of the Project, the full Holyrood TGS test year fuel savings by month would be credited to the Supply Cost Variance Deferral Account to partially offset the Project costs for each month. However, to ensure reliable service is provided to customers, Hydro is currently planning that the Holyrood TGS will continue to function as a fully capable standby facility until March 31, 2023. Hydro is currently evaluating whether operating the Holyrood TGS as a longer term backup facility is necessary or feasible.[34] Therefore, Hydro is proposing to credit the Supply Cost Variance Deferral Account (on a monthly basis) with the difference between the

[33] Numbers may not add due to rounding.
[34] These matters are the subject of the ongoing Reliability and Resource Adequacy Study review.

test year fuel costs reflected in customer rates and the actual No. 6 fuel costs incurred at the Holyrood TGS.[35]

Given that the balance in the existing RSP Hydraulic Production Variation component reflects Holyrood TGS fuel cost variances not yet recovered through customer rates, Hydro is proposing the balance in the RSP Hydraulic Production Variation component be transferred to this component of the Supply Cost Variance Deferral Account upon the approved effective date.

Hydro is also proposing to discontinue the Holyrood Conversion Rate Deferral Account and transfer any balance to another component of the Supply Cost Variance Deferral Account (as described in Section 6.7) upon its approved effective date.

6.3 Net Revenues From Exports

Based on Hydro's forecast load requirements to serve Island Interconnected System customers, Hydro will have excess Base Block Energy that it can export for many years into the future (i.e., once the Supply Period of the Muskrat Falls PPA has commenced). Hydro will recognize an estimate[36] of the exports incurred during the period at year-end.[37] Hydro is proposing all net revenues from exports[38] be credited to partially offset Project costs.

The proposed supply deferral account definition provides for the difference between the test year net revenues from exports and the year-end net revenues from exports[39] to be deferred for future disposition. As the 2019 Test Year did not reflect any net revenues from exports, the full amount of Hydro's net revenues from exports will be credited subsequent to the effective date of the deferral account until the implementation of a new test year for setting customer rates.

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[35] With the transition to the use of actual No. 6 fuel costs being charged to the deferral account, there is no longer a requirement to include the Holyrood TGS fuel conversion rate or the fuel price deviation in the determination of the costs to be deferred.
[36] As per terms of the agreement, actual exports will be finalized in the following period.
[37] Under IFRS, the recognition of the exports may not occur until the following period when actual exports are known. Under this circumstance, Hydro will recognize an IFRS deviation under IFRS 14 to ensure that an estimate of the exports is recorded in the period the export incurred.
[38] Net export revenue equals revenue from export sales less any expenses incurred in making the sale (e.g., transmission tariffs and marketing fees).
[39] Net revenues from exports will be based upon an estimate at year-end and recorded in the period the export occurred. Any difference between the estimate net revenues from exports and the actual will be transferred to the Supply Cost Variance Deferral Account in the following period.

The amount of energy available to be exported can vary depending on the variability in customer load requirements and variability in available supply. For example, higher hydrology levels than normal at on-island supply sources can provide an increase in the energy available for exports. This is a material shift from historic hydraulic supply variability which resulted in variations in No. 6 fuel costs. Net revenues from exports can also vary materially depending on fluctuations in market value.

Future non-firm sales to Island Industrial customers that are supplied from hydraulic generation will reduce the amount of energy available for export. To ensure Hydro's customers are not disadvantaged by increased non-firm sales, Hydro is proposing that non-firm sales supplied from hydraulic generation will be credited to this component of the proposed deferral account.[40]

6.4 Transmission Tariff Revenues

To export energy through the Newfoundland and Labrador Transmission System will require the payment of a "point-to-point" transmission tariff by the transmission customer that requires the transportation of the energy. The payment of the published transmission tariff to the Newfoundland and Labrador System Operator ("NLSO") will provide additional revenues to Hydro to partially offset Project costs. The amount of additional revenues will be dependent upon the transmission bookings each year.

Hydro is also required to pay a transmission tariff to enable the exporting of its excess energy. However, as Hydro is also the transmission asset owner, the NLSO credits the payments for using the transmission system back to Hydro. As a result, the amounts credited to this deferral account component will reflect tariff payments from parties other than Hydro.

The proposed deferral account definition provides for the difference between test year transmission tariff revenues paid by third parties to enable exports and actual transmission tariff revenues paid by third parties to enable exports to be deferred for future disposition. As the 2019 Test Year did not reflect any transmission tariff revenues from exports, all such revenues will be credited subsequent to the effective date of the deferral account until the implementation of a new test year for setting customer rates.

[40] The non-firm rate charged to customers when supply is provided by thermal sources recovers the cost of the thermal supply and would not impact the revenue from exports.

6.5 Greenhouse Gas Credit Revenues

The Government of Newfoundland & Labrador's *Management of Greenhouse Gases Act* came into effect on January 1, 2019. This legislation provides for Hydro to receive performance credits as the Holyrood TGS uses less fuel and decreases greenhouse gas emissions. Under the *Management of Greenhouse Gases Act*, Hydro may sell these performance credits to certain other facilities in the province, of which there are 14, excluding Holyrood TGS. The first year that Hydro was able to sell its performance credits was 2020. The qualifications and other specifics of how the performance credits are earned and can be sold are contained in the *Management of Greenhouse Gases Regulations*.[41]

In 2020, Hydro received 169,734 performance credits and sold 55,000 performance credits for $1.06 million. Hydro also sold 83,333 performance credits for approximately $2 million in early 2021. As credits do not expire until seven years after creation, unused performance credits are carried forward to apply to future compliance requirements or to be sold.

Upon implementation of the proposed Supply Cost Variance Deferral Account, Hydro proposes to credit the value earned by future sales of greenhouse gas credits to the Supply Cost Variance Deferral Account to help offset Project costs.

6.6 Other Island Interconnected System Supply Cost Variances

Hydro is proposing to discontinue the Revised Energy Supply Cost Variance Deferral Account upon the implementation of the proposed Supply Cost Variance Deferral Account. The Revised Energy Supply Cost Variance Deferral Account permits Hydro to defer certain price and volume variances from the approved test year for specific supply costs on Hydro's Island Interconnected System.[42] This deferral account is comprised of four main sections: (1) variations in the price and volume of standby thermal generation; (2) variations in the price and volume of off-island power purchases; (3) variations in volume only from on-island power purchases; and (4) fuel cost variations at the Holyrood TGS as a result of variations in energy production from sources specifically covered by the Revised Energy Supply Cost Variance Deferral Account.

Variances in sources historically covered by the Revised Energy Supply Cost Variance Deferral Account are largely beyond Hydro's control and have typically required Hydro to replace that energy with

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[41] https://www.assembly.nl.ca/Legislation/sr/Regulations/rc180116.htm.
[42] Variations in load, hydrology, and No. 6 fuel price are captured in the RSP.

generation from more expensive sources, primarily from the Holyrood TGS. Upon Project commissioning, variation from the test year forecast supply from these sources will impact the amount of energy available for export. Therefore, Hydro is proposing that the calculation in the proposed Supply Cost Variance Deferral Account will not refer to No. 6 fuel cost variations as there is a separate deferral account component to deal with net revenues from exports.

Hydro anticipates the filing of an application in the near-term to approve the purchase of the Exploits assets from government. If this transfer proceeds, Hydro will no longer incur the Exploits purchase power cost and the cost of Exploits will be reflected in Hydro's internal costs.

Table 4 provides the costs reflected in the 2019 Test Year for the Other Island Interconnected System Supply Costs (excluding Exploits). In the 2019 Test Year, Hydro incurred a cost of approximately $30.3 million for purchases of 757 GWh from Exploits.

Table 4: Other Island Interconnected System Supply Costs ($)
2019 Test Year

	Non-Utility Purchases	Off-Island Purchases[43]	Standby Thermal Generation[44]	Total
January	2,765,142	477,034	1,454,204	**4,696,380**
February	2,491,149	2,610,139	942,731	**6,044,019**
March	2,584,740	5,919,829	824,620	**9,329,189**
April	2,434,824	146,318	537,441	**3,118,583**
May	2,337,082	-	211,771	**2,548,853**
June	2,084,876	-	570,238	**2,655,114**
July	1,887,664	-	142,466	**2,030,130**
August	1,660,834	-	68,934	**1,729,768**
September	2,306,914	-	164,713	**2,471,627**
October	2,285,270	1,277,219	250,569	**3,813,058**
November	2,298,008	1,694,627	277,706	**4,270,341**
December	2,741,261	2,164,775	1,116,002	**6,022,038**
Total	**27,877,764**	**14,289,941**	**6,561,395**	**48,729,100**
MWh	270,580	481,499	22,730	774,809
Unit Cost (cents per kWh)	10.30	2.97	28.87	6.29

[43] Off-island purchases include purchases of Recapture Energy and Purchases over the Maritime Link.
[44] Standby Thermal Generation comprised of the Holyrood Gas Turbine, small diesel generators, and other gas turbines on the Island Interconnected System.

Table 4 shows that excluding Exploits purchases, Hydro's Other Island Interconnected System Supply Costs in the 2019 Test Year totalled $48.7 million reflecting an average unit cost of 6.3 cents per kWh and high cost variability depending on the source of supply. As a result, material increases or decreases in the quantity supplied by these sources can result in material changes in supply costs. Therefore, Hydro recommends the current approach to Other Island Interconnected System Supply Costs be continued in the proposed Supply Cost Variance Deferral Account; this will permit Hydro to defer supply cost variances relative to the test year for these sources, adjusted for the removal of changes in Holyrood TGS fuel costs. If the transfer of Exploits to Hydro proceeds, Hydro will then file an application to remove the impacts of Exploits supply variations from its deferral account.

Hydro is proposing to reproduce the existing deadband of +/- $500,000 per calendar year on this component of the Supply Cost Variance Deferral Account. Hydro is also proposing to transfer the balances in the Revised Energy Supply Cost Variance Deferral Account and the Holyrood Conversion Rate Deferral Account to the Other Island Interconnected System Supply Cost Variance component upon the effective date for the Supply Cost Variance Deferral Account.

6.7 Load Variations

The RSP includes a load variation component that removes earnings variances as a result of variation from the test year sales to Newfoundland Power and Hydro's Island Industrial customers. Hydro remains subject to earnings variances for sales variances to Hydro Rural customers and variances from test year demand revenues from Newfoundland Power and Island Industrial customers that change their power on order amounts between test years.

The requirement for the load variation component in the RSP has predominantly been a result of the material difference in the marginal revenues and marginal energy costs. The load variation component of the RSP is currently required to deal with the earnings impacts of load variations of Island Industrial customers because the energy price is derived based on the average embedded cost (4.428 cents per kWh) which is materially lower than the test year No. 6 fuel cost at the Holyrood TGS marginal cost (i.e., 18.165 cents per kWh). However, no load variation component has been required to deal with load variations from Newfoundland Power because the end block rate is currently priced at the test year Holyrood TGS fuel price.[45]

As explained earlier, variations in energy use on the Island Interconnected System impact the amount of energy available for exports. Under the current rate design for Newfoundland Power, if energy sales to Newfoundland Power increase or decrease relative to the 2019 Test Year forecast, then Hydro's revenues change by 18.165 cents per kWh. However, the current forecast of net export value for 2022 is currently in the range of 1 to 2 cents per kWh. Hydro has proposed that net revenues from exports be credited against Project costs. Therefore, relative to the test year forecast, energy sales reductions to Newfoundland Power will result in reduced earnings for Hydro by 18.165 cents per kWh and energy sales increases to Newfoundland Power will result in increased earnings for Hydro by 18.165 cents per kWh. Hydro believes the load variation component is still required on variations from Test Year energy sales, at least until revised rate structures are implemented reflecting the change in marginal energy costs to net revenues from exports. Therefore, Hydro proposes to defer the change in energy sales revenue from Newfoundland Power and Island Industrial customers as a result of load variations relative to the 2019 Test Year sales forecasts.[46]

The current RSP load variation component also requires the additional revenues resulting from firming up charges applied to secondary energy sales be credited to the benefit of customers.[47] Purchases of secondary energy from CBPP have historically provided No. 6 fuel savings that are flowed through to Newfoundland Power. Newfoundland Power pays Hydro a firming up charge to purchase the lower cost energy from CBPP and the firming up charges are credited to the RSP. However, after Project commissioning, the benefits of secondary energy purchases will be reduced materially and will be valued relative to the export market. Hydro will have excess energy available to serve customer load and does not foresee purchasing secondary energy from CBPP into the future; Hydro would also not project

[45] The marginal rate to Newfoundland Power was not always set based on the test year No. 6 fuel price. As a result, the load variation component still shows the calculations even though no balance in accumulating.

[46] Hydro notes that the financial impact from load variations from Island Industrial customers upon Project commissioning can also be material. For example, the change in North Atlantic Refining Limited load requirements as a result of their current operational status created a material load variation from that currently reflected in customer rates. Even with a marginal energy rate of slightly greater than 4 cents per kWh, such load volatility can materially impact Hydro's opportunity to recover its costs of supply.

[47] Hydro has a secondary purchase agreement in place to enable it to purchase surplus energy CBPP if such a purchase would provide system savings. There is also an agreement that enables Newfoundland Power to purchase this secondary energy from Hydro; however, Newfoundland Power is required to pay a firming up charge in addition to the cost incurred by Hydro for the purchase from CBPP. Hydro does not forecast secondary energy sales in its test year and therefore revenues from firming up charges for actual secondary energy sales are not reflected in the determination of test year revenue requirements.

any firming up charge revenues in the future. Therefore, the section of the RSP load variation component related to revenue from firming up charges is not reflected in the proposed load variation component of the Supply Cost Variance Deferral Account.[48]

6.8 Rural Rate Adjustments

6.8.1 Rural Rate Adjustment – Price Variation

The Rural Rate Adjustment transfers variations in revenues, resulting from changes in Hydro's Rural Rates between test years, into the Newfoundland Power Rate Stabilization Account. As a result, if retail rates increase between test years, Hydro transfers the estimated additional revenue resulting from the rate increase to the benefit of the customers of Newfoundland Power. Hydro is proposing to continue this approach in dealing with changes in revenue resulting from price changes to Hydro Rural customers.

6.8.2 Rural Rate Adjustment – Load Variation

The Rural Rate Adjustment does not currently deal with earnings impacts of sales volume variations to Hydro Rural customers. The structure of the Project agreements creates the potential for material earnings volatility if sales to Hydro Rural customers on the Island Interconnected System vary from the test year forecast. The average unit revenue in the 2019 Test Year on the Island Interconnected System is approximately 12.34 cents per kWh. As a result, energy sales reductions relative to the test year load forecast to Hydro Island Interconnected System Rural customers will result in reduced earnings for Hydro by 12.34 cents per kWh (on average) and energy sales increases to Hydro Island Interconnected System Rural customers will result in increased earnings for Hydro by 12.34 cents per kWh (on average). For example, Hydro's 2019 sales to Hydro Rural Island Interconnected System customers were 26 GWh higher than the 2019 Test Year forecast; a sales increase of this amount after Project commissioning would provide approximately $3.2 million in additional earnings to Hydro.[49] Hydro would also bear the risk of comparable earning losses if sales decline by the same amount.

Hydro is proposing to expand the Rural Rate Adjustment, which currently transfers changes in rural revenues as a result of price changes, to also include changes in revenues for Hydro Rural Island Interconnected System customers resulting from sales variances from the test year load forecast. This

[48] Once a revised rate structure is established for Newfoundland Power reflecting the reduced system marginal energy cost, there would be no longer savings to Newfoundland Power by purchasing firmed up CBPP energy from Hydro.
[49] Prior to Project commissioning, marginal revenue changes were offset by changes in No. 6 fuel costs at the Holyrood TGS.

modification is required to enable Hydro to recover the supply costs incurred to serve Hydro's Island Interconnected System Rural customers which do not vary with changes in customer usage.

6.9 Isolated Systems Supply Cost Variances

In Order No. P.U. 22(2017), the Board approved the Isolated Systems Supply Cost Variance Deferral Account. This account permits Hydro to defer price variances from the approved test year related to fuel and power purchases in Hydro's Isolated systems. This deferral account does not allow for recovery of variances as a result of changes in volume, as changes in volume are partially offset by changes in revenue. The Isolated Systems Supply Cost Variance Deferral Account includes a deadband of +/- $500,000 per calendar year. As such, Hydro is only permitted to defer annual cost variances in excess of +/- $500,000 resulting from price changes relative to the Test Year cost of supply.

Table 5 provides the amounts of disposition from/ (to) customers for the period 2015–2020. The amounts provided represent the amounts after consideration of the deadband of $500,000 for each year.

Table 5: Isolated Systems Supply Cost Variance Deferral Account Transfers ($000s)

Year	2015	2016	2017	2018	2019	2020	Total
Balance	-	(2,187)	(1,107)	1,089	(347)	(3,998)	(6,549)

Table 5 shows customer received savings of approximately $6.5 million through the use of the Isolated Systems Supply Cost Variance Deferral Account for the period 2015–2020. Hydro is proposing to include the Isolated Systems Supply Cost Variances as a component in the Supply Cost Variance Deferral Account.

6.10 Utility and Industrial Plan Balances

Hydro is proposing to create a Utility balance component and Industrial balance component in the Supply Cost Variance Deferral Account and transfer the balances from the RSP upon implementation of the proposed deferral account. Transfers to the Utility balance and the Industrial balance will continue to be required on a monthly basis as a result of the ongoing balance dispositions and the disposition of forecast fuel rider savings/savings currently reflected in monthly RSP adjustments.[50] As Hydro is not yet proposing an allocation and recovery approach for new transfers to the Supply Cost Variance Deferral Account, with the exception of the Rural Rate Alteration transfers which only apply to Newfoundland Power, no other transfers specific to the Utility balance and Industrial balance will occur until further approval is obtained by the Board.[51]

The Utility and the Industrial balances are used in computing the RSP Current Plan Adjustments to apply on an annual basis for each customer class. Hydro is proposing that for 2022, the normal rate updates previously required under the RSP (scheduled January for Island Industrial customers and July for Newfoundland Power) will reflect the discontinuance of the fuel riders and the recovery of the remaining current plan balances.[52]

6.11 Cost Recovery and Financing Costs

Hydro is uncertain when rate mitigation will be available to offset the costs to be deferred in the proposed Supply Cost Variance Deferral Account. Without knowing the magnitude of the amounts to be recovered from customers, Hydro is not yet prepared to propose a recovery period for the deferred costs. Hydro also believes it is appropriate to have the details on the costs deferred in each component of the proposed deferral account prior to proposing an allocation approach among customer classes. For deferral account components strictly related to Hydro Rural cost recovery, industrial customers are excluded from the allocation in accordance with the provisions of the *Electrical Power Control Act*. Hydro plans to file a separate application in future to deal with the balance disposition in the proposed Supply Cost Variance Deferral Account.

The RSP requires Hydro to apply its weighted average cost of capital (“WACC”) to the outstanding plan balances (both positive and negative balances). As WACC is applied to deferral account balances when included in rate base, Hydro does not include the RSP balance in test year rate base for rate setting

[50] These billing adjustments are applied in accordance with Board approvals of annual RSP rate updates (i.e., fuel riders and recovery rate adjustments).
[51] The balance in the Isolated Diesel Systems component is also required to be recovered from Newfoundland Power. However, Hydro is required to file a report annually in its justification for disposition of this balance. Therefore, Hydro is not proposing an automatic transfer to the Utility balance.
[52] Without knowing the terms of the rate mitigation plan, there is uncertainty with respect to what level of rate increase will be required for customers in 2022. As a result, Hydro may need to consider if RSP balance recoveries may need to extend beyond the normal one-year recovery period.

purposes.[53] RSP balances have historically varied materially from amounts owing from customers and amounts owing to customers. Applying financing costs to the deferral account balance as it varies rather than including a forecast fixed balance in rate base provides a better reflection of the financing costs incurred by Hydro in maintaining the deferral account. Hydro believes it is appropriate to continue this approach with respect to the balances in the Supply Cost Variance Deferral Account. This approach is reflected in the proposed Supply Cost Variance Deferral Account provided in Appendix A.

7.0 Holyrood TGS Accelerated Depreciation

7.1 General

As previously introduced, the planned end of generation at the Holyrood TGS as of March 31, 2023 is projected to contribute to a material increase in depreciation expense in 2022. The capital investments incurred to enable the Holyrood TGS to reliably and safely operate in standby mode for a period of time after Project commissioning provide cost volatility concerns for Hydro.

7.2 Operational Plan Uncertainty

There continues to be uncertainty as to whether a further extension of the Holyrood TGS as a fully available generation facility will be required beyond March 31, 2023. A review of the feasibility of the Holyrood TGS as a backup supply facility beyond its current planned retirement date is ongoing as part of the Resource and Reliability Adequacy Study.

The current long-term plan for the Holyrood TGS is its retirement as a generating facility and conversion to operation as a synchronous condenser. In this operational mode, Holyrood TGS Unit 3 would operate as a synchronous condenser no longer capable of conversion to a generator and Units 1 and 2 would be decommissioned.

To a large degree, the requirement to continue operation as a fully operational facility requires Hydro to continue to maintain its personnel, equipment inventory, fuel inventory, assets, contractor agreements, etc. to similar levels as required for the Holyrood TGS' full operation prior to Project commissioning. Hydro estimates an approximate staff decrease of 50 full-time equivalents upon transitioning to the post-steam operational mode.

[53] The inclusion of deferral account balances in rate base is consistent with the Asset Rate Base Method approved by the Board.

Hydro will present a proposal in its next GRA to deal with managing the uncertainty in operating and depreciation cost in determining its test year revenue requirement. However, in the short-term Hydro is projecting a material increase in depreciation expense in 2022 that is not reflected in existing customer rates.

7.3 Holyrood TGS Accelerated Depreciation

As noted above, Hydro is projecting a material increase in depreciation expense for the Holyrood TGS in 2022 as a result of the use of accelerated depreciation and the projected end of generation date of March 31, 2023.

Due to the current end of service assumption for the Holyrood TGS, capital expenditures for this facility to operate as a generator continue to be required. Hydro is investing approximately $13.3 million in capital in 2021 and is proposing to invest $8.8 million in 2022 to ensure the Holyrood TGS will continue to operate reliably until March 31, 2023, (i.e., for two winter seasons after the planned commissioning of the Project late in 2021).[54] Depreciation on these investments is required to be calculated on an accelerated basis (i.e., monthly depreciation = capital investment divided by remaining months of service life). For example, $13.3 million in capital investment put in service in the quarter of 2021 would be depreciated over 18 months and impact costs by $2.2 million in 2021, $8.9 million in 2022 and $2.2 million in 2023.[55] The projected $8.8 million of capital investments required in 2022 would typically need to be treated as an operating cost as the expected service life would be less than 12 months. There are also $18.2 million[56] in Holyrood TGS asset costs from years prior to 2021 that are currently subject to accelerated depreciation over the period January 1, 2022 to March 31, 2023.

Table 6 provides the accelerated depreciation expenses for the Holyrood TGS comparing the 2019 Test Year to the 2020 actual and forecast depreciation for the period 2021–2023.

[54] The investment includes the Holyrood TGS In-Service Failure program, of which the type of Holyrood TGS asset is not defined. For example, for 2022 Hydro has assumed that of a $2 million Holyrood in-service failure program that $1.66 million (83%) relates to assets that would not be required post-steam.
[55] Assumes there would be 3 months amortization in 2021 and 2023.
[56] Projected net book value as of December 31, 2021 of Holyrood TGS generation assets in service prior to 2021.

Table 6: Holyrood TGS Accelerated Depreciation Expense ($ millions)

2019 Test Year	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
16.9	16.3	16.8	32.2	5.9

Table 6 shows that if March 31, 2023 is the end of life as a generation facility, the accelerated depreciation for the Holyrood TGS in 2022 will be $32.2 million,[57] $15.3 million higher than the depreciation expense currently reflected in customer rates.

If the life of the Holyrood TGS as a generation facility is extended the 2022 accelerated depreciation expense for the Holyrood TGS would materially reduce relative to forecast and the depreciation expense in a future year would materially increase. However, the degree of change in accelerated depreciation will depend on the term of the life extension and the additional capital investment required.

As a result of both the uncertainty in the concluding date for the Holyrood TGS as a generation facility and the resulting material depreciation cost volatility, Hydro believes it would be appropriate to establish a deferral account to defer the difference between the actual accelerated depreciation at the Holyrood TGS in 2022 and the approved 2019 Test Year costs.

Appendix B provides the proposed account definition for the Holyrood TGS Accelerated Depreciation Deferral Account.

8.0 Financial Reporting of Project Costs

8.1 General

Hydro is proposing to recognize the power purchase costs relating to the delivery of post-commissioning energy in accordance with the terms of the Project agreements, with the exception of repayable advances made to affiliates which will be treated as loans.[58]

[57] The forecast $34.1 million is comprised of $27.1 million of Holyrood TGS accelerated depreciation and $7.8 million of capital costs that may be required to be treated as operating costs because they are in service less than 12 months.
[58] The Muskrat Falls PPA includes a payment requirement referred to as the Base Block Capital Cost Recovery Adjustment, which are repayable, interest-bearing advances from Hydro to Muskrat Falls. These advances are required to be accounted for as loans.

As stated earlier, the Muskrat Falls PPA requires Hydro to fund the sustaining capital costs through capital contributions for the Muskrat Falls generation and the LTA assets as a portion of the annual O&M cost payments under the Muskrat Falls PPA. Recognition of the sustaining capital costs in this manner does not provide a matching of the recognition of the expense with the timing of the benefit provided by investment. Therefore, Hydro is also proposing to establish a deferral account to temporarily deal with Hydro costs for sustaining capital under the Muskrat Falls PPA until a long-term approach is considered in Hydro's next GRA. This section of the evidence provides more detail on Hydro's proposals with respect to its financial reporting of Project costs.

8.2 Background

The annual payments by Hydro under the Muskrat Falls PPA and the TFA are projected to comprise greater than 70% of the annual cost of serving Island Interconnected System customers. While it is required pursuant to Order in Council OC2013-343 that the full Project costs be recovered in accordance with the terms of the Project agreements, a review of the payment terms and the accounting standards was necessary to determine the annual Project costs to be recognized as capital and operating expenses for use in determining Hydro's test year revenue requirement.

Hydro applies IFRS for financial reporting for regulatory purposes.[59] Hydro also elected to adopt IFRS 14 — *Regulatory Deferral Accounts,* which permitted Hydro to continue to account for regulatory deferral account balances in accordance with Canadian Generally Accepted Accounting Principles in its initial adoption of IFRS and subsequent financial statements. The adoption of IFRS 14 – *Regulatory Deferral Accounts* resulted in changes for financial statement presentation purposes only, with no impact on ratepayers.

Hydro has determined it will be required to recognize power purchase expense in a manner that is different from the commercial terms of the Project agreements during both the delivery of pre-commissioning energy and for deliveries post-commissioning. In order to align Hydro's accounting recognition with the commercial terms of the agreement, it was determined that an accounting deviation, under IFRS 14 – *Regulatory Deferral Accounts* was required. In P.U. 9(2021), the Board approved Hydro's proposal to deviate from IFRS, using IFRS 14 – *Regulatory Deferral Accounts*, which would allow Hydro to recognize the power purchase costs relating to the delivery of pre-commissioning

[59] Hydro adopted IFRS in accordance with Board Order No. P.U. 13(2012) as of January 1, 2014.

energy in accordance with the terms of the commercial terms of the Muskrat Falls PPA to enable the displacement of more expensive thermal generation to the benefit of Island Interconnected System customers.

Hydro is proposing a continuation of this approach post-commissioning to avoid impacts of non-cash accounting expenses associated with the Project agreements on Hydro's revenue requirement and/or net income.

8.3 Purchase Power Expense Reporting

The payment terms of the Project agreements are structured to recover the Project costs primarily using fixed payments by Hydro each month as the monthly charges to Hydro do not vary by the amount of energy purchases.[60] However, IFRS requires Hydro to recognize the costs under the Muskrat Falls PPA and the TFA in a manner that will not match the payment terms.[61]

The IFRS treatment of the power purchase expense looks at certain full Project costs over the term of the contracts which includes projected sustaining capital costs. For example, in the case of the Muskrat Falls PPA, planned sustaining capital costs projected to be incurred in the 49th year of the contract would be allocated over the 50-year life of the contract beginning in year one and would result in Hydro recognizing a portion of these expenditures in each year of the 50-year term. The recognition of the allocation of full Project costs over the life of the contract in this manner in determining test year revenue requirement can result in the recovery of forecast long-life asset costs prior to incurring the capital expenditures. Under the Muskrat Falls PPA, recognition under IFRS also requires certain costs to be forecasted for the entire life of the contract and split between the capacity and energy performance obligations. The costs related to energy are divided by the projected kWh to be delivered over the life of the project to derive a cent per kWh cost for use in cost recognition. The costs related to capacity are recognized evenly on a straight-line basis over the term of the agreement.

Application of IFRS to Project costs will result in annual purchase power costs which are different than the annual purchase payments required under the terms of the Project agreements. Hydro has no reason to believe that requirements of IFRS 15, that require the recognition of purchase power expense

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[60] Hydro is also required to make monthly payments under the Project agreements in advance of receiving service (i.e., payments required on the first day of each month).

[61] Under IFRS 15 – *Revenue from Contracts with Customers*, companies must recognize revenues consistent with the completion of the performance obligations under a contract, irrespective of the contractual timing of cash payments.

on a basis that differs from the payment terms of the Project agreements, will change in the foreseeable future. Therefore, Hydro is proposing to recognize purchase power expense related to Project costs in accordance with the payment terms.[62]

The proposed approach would avoid impacts of non-cash accounting expenses[63] associated with the Project agreements on Hydro's revenue requirement and/or net income. Under IFRS 14, the deviation would result in a regulatory adjustment on Hydro's income statement and a corresponding regulatory asset or liability on Hydro's balance sheet. The accounting deviation would have no impact on customers. In addition, the treatment will be consistent with Hydro's past regulatory accounting practices of recognizing purchase power expenses in accordance with the payment terms of the agreements, such as the Exploits Power Purchase Agreement, capacity assistance agreements, wind purchase agreements, etc., and the pre-commissioning IFRS deviation approved by the Board Order in No. P.U. 9(2021).

8.4 Muskrat Falls Sustaining Capital

The Muskrat Falls PPA requires Hydro to fund the sustaining capital costs of the Muskrat Falls generating facilities and the LTA at the time the expenditures are incurred. As discussed earlier, under IFRS 15 the forecasted power purchases, including sustaining capital costs, are allocated between energy and capacity. As a result, Hydro is required to recognize forecasted sustaining capital costs as each kWh of energy is delivered and as the straight-line capacity expense is recognized over the life of the contract.[64] Hydro believes an approach which recognizes the sustaining capital costs throughout the life of the agreement is inconsistent with inter-generational equity as customers would be required to pay for future sustaining capital investments prior to the costs being incurred. Also, recognizing the sustaining capital costs consistent with the commercial terms as up-front payments would similarly not be appropriate, as it would result in the recovery of the costs of long-life assets in the period incurred; this also would be inconsistent with inter-generational equity and could contribute to rate volatility.

[62] 'Payment terms' is defined for this regulatory deferral as the amount invoiced for the period the service is provided and would exclude pre-payments in advance of the period of service. Any pre-payments would be recognized in the period the service is provided.

[63] Including non-cash revenue and expenses associated with financial instruments, if applicable.

[64] The Muskrat Falls plant and LTA sustaining capital will be recognized based upon energy being delivered and capacity over the life of the agreement.

Hydro proposes to establish a regulatory deferral account to deal with the required payments for sustaining capital ("Muskrat Falls PPA Sustaining Capital Deferral Account"). Upon payment of sustaining capital costs, Hydro would defer the payments and interest incurred during construction in funding the sustaining capital. In its next GRA, Hydro will present evidence and a proposal for an approach for recovery of sustaining capital incurred under the Muskrat Falls PPA.

Appendix C provides the proposed Muskrat Falls PPA Sustaining Capital Deferral Account Definition.

Appendix D provides a summary of the proposed accounting treatment of the charges to be incurred under the Project agreements.

9.0 Summary

The proposed Supply Cost Variance Deferral Account will serve to enable deferral of material supply cost variances from those reflected in current rates until the conclusion of Hydro's next GRA. The proposed Supply Cost Variance Deferral Account is also structured to enable rate mitigation funding and/or billings from rate increases to recover Project costs to apply to reduce the balance owing from customers. Hydro is proposing that the Supply Cost Variance Deferral Account will become effective in the month when the initial payment is required under the Muskrat Falls PPA. The proposed Supply Cost Variance Deferral Account provides for the transfer of the balances in Hydro's existing supply cost deferral accounts to the proposed Supply Cost Variance Deferral Account and the conclusion of the RSP adjustments currently reflected in customer rates.

Hydro proposes to file a future application with the Board, subsequent to the next GRA Order, to deal with allocation and recovery of the balance in the Supply Cost Variance Deferral Account that accumulates prior to the conclusion of the next GRA. In its next GRA, Hydro will provide additional evidence on a long-term approach to the Supply Cost Variance Deferral Account which will include a proposed allocation and recovery approach to the deferral account balances that will accumulate subsequent to Project costs and rate mitigation being reflected in customer rates.

Hydro is projecting a material increase in accelerated depreciation expense for the Holyrood TGS in 2022 as a result of the current projected end of generation date of March 31, 2023 and the required continued capital investments to maintain the facility to operate in a safe and reliable manner. Hydro is proposing a deferral account to deal with the projected material increase in accelerated depreciation expense at the Holyrood TGS for 2022.

The application of IFRS requirements to Project costs will result in annual purchase power cost variability that will not reflect the financial impacts on Hydro of annual purchases under the terms of the Project agreements. Hydro is proposing to deviate from IFRS, using IFRS 14, to enable the financial reporting of payments under the Project agreements on a basis relatively consistent with current regulatory practice. Hydro is also proposing to establish a deferral account to deal with the Muskrat Falls PPA requirement for Hydro to effectively treat sustaining capital payments as an O&M cost. Hydro will provide additional evidence in its next GRA on the proposed approach to recovery of the costs resulting from sustaining capital charges under the Muskrat Falls PPA.

Board approval of Hydro's proposals described in this evidence and requested in the Application will (i) enable Hydro to defer the net increase in costs incurred by Hydro as a result of the Project until rate mitigation is provided by government or a cost recovery plan can be established for future recovery from customers; (ii) enable the supply cost deferral accounts to operate and reflect changes in future supply cost variability on the Island Interconnected System; and (iii) be consistent with legislation and provide Hydro the opportunity for recovery of Project charges.

Approval of Hydro's proposals will contribute to enabling Hydro's next GRA to proceed in an orderly manner to enable the development of a long-term plan for establishment of customer rates to provide recovery of Project costs, net of rate mitigation funding that may be available.

Appendix A

Proposed Supply Cost Variance Deferral Account Definition

Proposed Supply Cost Variance Deferral Account Definition

The Supply Cost Variance Deferral Account of Newfoundland and Labrador Hydro ("Hydro") is established to smooth rate impacts for Hydro's Utility customer, Newfoundland Power Inc. ("Newfoundland Power"), and Island Industrial customers and to provide Hydro the opportunity to recover supply cost variances between the forecasts reflected in customer rates and the actual costs incurred.

The formulae used to calculate the plan's activity are outlined below. Positive values denote amounts owing from customers to Hydro whereas negative values denote amounts owing from Hydro to customers.

Section A

1.0 Muskrat Falls Project ("Project") Cost Variances

The **Project Cost Variances** will reflect the variance from test year costs for the Muskrat Falls Purchase Power Agreement ("Muskrat Falls PPA") and the Transmission Funding Agreement ("TFA").

Project Cost Variances will be calculated monthly based on the following formula:

$$(A - A_T) + (B - B_T)$$

Where:

A = Actual Purchased Power Expense from Muskrat Falls PPA Charges;

A_T = Test Year Purchased Power Expense from Muskrat Falls PPA Charges;

B = Actual Purchased Power Expense from TFA Charges; and

B_T = Test Year Purchased Power Expense from TFA Charges.

2.0 Rate Mitigation Fund

Any funding provided by the Government of Newfoundland and Labrador to provide rate mitigation to offset the costs of the Project will be credited to the **Rate Mitigation Fund**.

3.0 Project Cost Recovery

Charges applied to customers to recover Project costs will be credited to the **Project Cost Recovery** component of the deferral account and tracked by customer class.

4.0 Holyrood Thermal Generating Station ("Holyrood TGS") Fuel Cost Variance

Holyrood TGS Fuel Cost Variances will be calculated monthly based on the following formula:

$$(C - C_T)$$

Where:

C = Actual Holyrood TGS Fuel Cost incurred in the month to supply firm energy to customers on the Island Interconnected System; and

C_T = Test Year Holyrood TGS Fuel Cost in the month to supply firm energy to the customers on the Island Interconnected System.

The balance in the Rate Stabilization Plan ("RSP") Hydraulic Production Variation component shall be transferred to the **Holyrood TGS Fuel Cost Variance** component upon the effective date of the initial approval of the Supply Cost Variation Deferral Account.

5.0 Other Island Interconnected System Supply Cost Variance

The balances in the Revised Energy Supply Cost Variance Deferral Account and the Holyrood Conversion Rate Deferral Account will be transferred to this account on the effective date of the Supply Cost Variance Deferral Account.

This account shall be charged or credited monthly with the **Other Island Interconnected System Supply Cost Variance** incurred by Hydro on the Island Interconnected System that is in excess of the Cost Variance Threshold in the calendar year.

Variations resulting from both the price and volume of the following thermal generation sources shall be charged or credited to this account:

- Holyrood Combustion Turbine;
- Hardwoods Gas Turbine;
- Stephenville Gas Turbine;
- St. Anthony Diesel Plant; and
- Hawkes Bay Diesel Plant.

Variations resulting from the volume of the following on-island power purchases shall be charged or credited to this account:

- Nalcor Exploits;
- Star Lake;
- Rattle Brook;
- Corner Brook Pulp and Paper Limited ('CBPP") Cogeneration;

- St. Lawrence wind; and
- Fermeuse wind.

Variations from the price and volume of firm energy power purchases from CBPP shall be charged or credited to this account.

Variations resulting from the cost of off-island power purchases shall also be charged or credited to this account. Off-island power purchase costs shall not include any expenditure related to Muskrat Falls PPA, TFA or the Interim TFAs.

The **Other Island Interconnected System Supply Cost Variance** will be determined monthly by the following formula:

$$D + E + F + G$$

D = Test Year Thermal Generation Variances resulting from both price and volume;

Where:

D = (Actual Thermal Generation Cost in providing firm energy – Test Year Thermal Generation Cost).

E = Test Year Off-Island Power Purchase Variances resulting from both price and volume;

Where:

E = (Actual Off-Island Power Purchase Cost – Test Year Off-Island Power Purchase Cost).

F = Test Year Power Purchase Variances resulting from volume;

Where:

F = (Actual kWh Purchases – Test Year kWh Purchases) x (Test Year Purchase Cost in $/kWh).

G = Variances based on firm energy purchases from CBPP;

Where:

G = (Actual CBPP Power Purchase Cost – Capacity Assistance Adjustment) – (Test Year CBPP Firm Energy Power Purchase Cost).

"Capacity Assistance Adjustment" shall represent any change in fixed capacity assistance payments as a result of firm energy purchases from CBPP.

The **Cost Variance Threshold** equals ±$500,000 in a calendar year.

6.0 Net Revenue From Exports Variance

The **Net Revenue from Exports Variance** is computed on monthly basis by the following formula:

$$(H_T - H)$$

Where:

Net Revenue from Exports reflect the revenues from Hydro exports less the costs incurred to export energy.

H_T = Test Year Net Revenues from Exports ($); and

H = Actual Net Revenues from Exports ($).

The account will be credited with an estimate of net export sales that occurred during the year in December but the actual settlement value will not be finalized until the following period. The account will be adjusted in the following period for any difference between the estimated and actual value.

Revenues from non-firm sales on the Island Interconnected System supplied by hydraulic generation will also be credited to the Net Revenue from Exports Variance component.

7.0 Transmission Tariff Revenue Variance

For the purpose of this deferral account, Transmission Tariff Revenues reflect the transmission revenues paid by third parties to enable exports. The ***Transmission Tariff Revenue Variance*** is computed on monthly basis by the following formula:

$$(I_T - I)$$

Where:

I_T = Test Year Transmission Tariff Revenues paid by third parties ($); and

I = Actual Transmission Tariff Revenues paid by third parties ($).

8.0 Load Variation

Firm: Firm load variation is determined based on the revenue variation for firm energy sales compared with the test year Cost of Service Study firm sales. It is calculated separately for Newfoundland Power firm sales and Island Industrial firm sales on a monthly basis, in accordance with the following formula:

$$(J_T - J_A) \times K_R$$

Where:

J_T = Test Year Cost of Service Firm Sales, by customer class (kWh);

J_A = Actual Firm Sales, by customer class (kWh); and

K_R = Firm Energy Rate, by customer class.

Where the rate designs include more than one energy block, the excess energy rate will apply in computing **Load Variation** transfers.

9.0 Rural Rate Alteration

The **Rural Revenue Adjustment** transfers to Newfoundland Power: (i) changes in Hydro Rural revenues resulting from changes in Rural Rates between test years, and (ii) changes in Rural revenues on the Island Interconnected System as a result of changes in Rural load between test years. The **Rural Revenue Adjustment** is calculated on a monthly basis, in accordance with the following formula:

$$[(N_T-N_A) \times O_T] + [(P_T-P_A) \times Q_T]$$

Where:

N_T = Test Year Cost of Service rural rates;

N_A = Existing rural rates;

O_T = Test Year Billing Units (kWh, bills, billing demand);

P_T = Test Year kWh sales for Hydro Rural Island Interconnected (excluding street and area lighting);

P_A = Actual kWh sales for Hydro Rural Island Interconnected (excluding street and are lighting); and

Q_T = Test Year rates per class for Rural Island Interconnected system (excluding street and area lighting).

10.0 Isolated Systems Supply Cost Variance

The balances in the Isolated Systems Supply Cost Variance Deferral Account will be transferred to this account on the effective date of the Supply Cost Variance Deferral Account.

This account shall be charged or credited with the amount by which Hydro's Isolated Systems Supply Cost Variance exceeds the Supply Cost Variance Threshold in a calendar year.

The **Isolated Systems Supply Cost Variance** will be determined by the following formula:

$$R \times (S_A - S_T)$$

Where:

R = Total actual supply produced and purchased (kWh) on Hydro's isolated systems;

S_A = (Total actual cost of No. 2 fuel used to provide energy plus the total actual cost of purchases) divided by the total of the (actual kWh production and the actual kWh purchases) in $/kWh; and

S_T = (Total Test Year cost of No. 2 fuel used to provide energy plus the total Test Year cost of purchases) divided by the (total of the Test Year kWh production and the Test Year kWh purchases) in $/kWh.

The **Supply Cost Variance Threshold** equals ±$500,000 in a calendar year.

11.0 Greenhouse Gas Credit Revenues Variance

The **Greenhouse Gas Credit Revenues Variance** is computed on monthly basis by the following formula:

$$(T_T - T)$$

Where:

T_T = Test Year Greenhouse Gas Credit Revenues ($); and

T = Actual Greenhouse Gas Credit Revenues ($).

Section B

1.0 Rate Stabilization Plan ("RSP") Conclusion

1.1 Plan Balances

The separate RSP Current Plan balances for Newfoundland Power and the Island Industrial customer class will be transferred to this account on the effective date of the Supply Cost Variance Deferral Account.

Separate plan balances will be maintained in this account. Transfers to the Utility balance and the Industrial balance will continue to be required on a monthly basis as a result of the disposition of RSP Current Plan balances and the RSP fuel rider amounts currently reflected in the approved RSP adjustments.[1] Transfers to the Utility balance will continue to reflect the monthly adjustments for the **Rural Rate Alteration**.

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[1] These billing adjustments are applied in accordance with Board approvals of annual RSP rate updates (i.e., fuel riders and recovery rate adjustments).

No other transfers to the Utility balance and Industrial Customer balance will occur until further approval is obtained by the Board of Commissioners of Public Utilities ("Board").

1.2 Conclusion of RSP Fuel Riders and Disposition of RSP Current Plan Balances

Newfoundland Power

The RSP fuel rider, established based on the Newfoundland Power Fuel Price Projection amount, shall be set to zero in 2022. The disposition of the remaining RSP Current Plan balances will be addressed in the application to the Board for the discontinuance of the RSP fuel rider.

The revision to the Utility Rate RSP adjustments described above is scheduled for July 1, 2022. However, the timing of the required rate revision will depend of the implementation schedule for the rate mitigation plan.

Island Industrial

The RSP fuel rider established based on the Island Industrial customer Fuel Price Projection amount shall be set to zero in 2022. The disposition of the remaining RSP Current Plan Balances will be addressed in the applications to the Board for the discontinuance of the RSP fuel riders.

The revision to Industrial Customer RSP rate adjustments described above is scheduled for January 1, 2022. However, the timing of the required rate revision will depend of the implementation schedule for the rate mitigation plan.

Section C

1.0 Financing Costs

Financing charges on the plan balances will be calculated monthly using Hydro's approved test year weighted average cost of capital.

2.0 Customer Allocation

Customer Allocation of balances in the Supply Cost Variance Deferral Account will be subject to a further approval by the Board. However, the **Rural Rate Alteration** and the **Isolated Systems Supply Cost Variance** will not be allocated for recovery from Island Industrial customers.

3.0 Balance Disposition

Disposition of balances in the Supply Cost Variance Deferral Account will be subject to a further approval by the Board.

4.0 Balance Transfers

The balances in the Supply Cost Variance Deferral Account shall be adjusted by other amounts as ordered by the Board.

Appendix B

Proposed Holyrood TGS Accelerated Depreciation Deferral Account Definition

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Proposed Holyrood TGS Accelerated Depreciation Deferral Account Definition

The Holyrood Thermal Generation Station ("Holyrood TGS") Accelerated Depreciation Deferral Account of Newfoundland and Labrador Hydro is established to defer for future recovery the difference between the accelerated depreciation expense for the Holyrood TGS in 2022 and the accelerated depreciation expense for the Holyrood TGS included in the approved 2019 Test Year.

The disposition of the balance in this account will be subject to a further Order of the Board of Commissioners of Public Utilities.

Appendix C

Proposed Muskrat Falls PPA Sustaining Capital Deferral Account Definition

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Proposed Muskrat Falls PPA Sustaining Capital Deferral Account Definition

This account shall be charged with the costs incurred by Newfoundland and Labrador Hydro ("Hydro") in accordance with the terms of the Muskrat Fall Power Purchase Agreement ("Muskrat Falls PPA") associated with Hydro's funding of sustaining capital for the Muskrat Falls Hydroelectric Generating Facility ("Muskrat Falls Plant") and Labrador Transmission Assets ("LTA"). The amount charged to this account will include the amount of payments for the sustaining capital and the interest during construction ("IDC") incurred by Hydro, as calculated in accordance with Hydro's Capitalization Guidelines.

This account will be charged at the conclusion of each calendar month based upon the following:

Monthly Transfer = Hydro's Actual Monthly Sustaining Capital Payments for the Muskrat Falls Plant and LTA + Hydro's IDC

Disposition of any Balance in this Account

Disposition of the balance in this account will be subject to a further Order of the Board of Commissioners of Public Utilities.

Appendix D

Summary of Proposed Regulatory Accounting for Muskrat Falls Project Charges

Summary of Proposed Regulatory Accounting for Muskrat Falls Project Charges

Contract	Article	Expense Type		Particular	Regulatory Mechanisim
Muskrat Falls PPA[1]	4.2	Base Block Capital Cost Recovery	Capital Cost Recovery and Return		IFRS[2] Deviation - Treat consistent with commercial payment
Muskrat Falls PPA	4.2	O&M[3] Costs	O&M	O&M	N/A - Treat consistent with IFRS
				Payments Pursuant to Real Property, Leases, Licenses or Easements	N/A - Treat consistent with IFRS
				Indemnity Payments	N/A - Treat consistent with IFRS
				Taxes	N/A - Treat consistent with IFRS
			Operations Finance Costs		IFRS Deviation - Treat consistent with commercial payment
			Sustaining Capital Costs		Deferred until approach to be dealt with in Hydro's next GRA[4]
			IBA[5] Payments		IFRS Deviation - Treat consistent with commercial payment
			Water Lease		N/A - Treat consistent with IFRS
			LTA[6] Payments	LTA Capital Cost Recovery and Return	IFRS Deviation - Treat consistent with commercial payment
				LTA O&M	IFRS Deviation - Treat consistent with commercial payment
				LTA Sustaining Costs	Deferred until commercial payments are completed. Upon commercial payment, sustaining capital will be transferred to a separate deferral and treated consistent with property, plant and equipment
				LTA Operating Financing Costs	IFRS Deviation - Treat consistent with commercial payment
				IBA Payments	IFRS Deviation - Treat consistent with commercial payment
				Payments Pursuant to Real Property, Leases, Licenses or Easements	IFRS Deviation - Treat consistent with commercial payment
				Indemnity Payments	IFRS Deviation - Treat consistent with commercial payment
				Taxes	IFRS Deviation - Treat consistent with commercial payment
Muskrat Falls PPA	4.3	Nominal Annual Amount of $1		Supplementary Block Energy Payment	IFRS Deviation - Treat consistent with commercial payment
Muskrat Falls PPA	4.4	Nominal Annual Amount of $1		Ancillary Services	N/A - Treat consistent with IFRS
Muskrat Falls PPA	4.5			External Market Energy Sales	Export revenue recognized in the period occurred[7]
Muskrat Falls PPA	Sch. 1, Sec. 4			Affiliate Loan Payments	N/A - Treat consistent with IFRS

Contract	Article	Expense Type	Particular	Regulatory Mechanisim
TFA[8]	3.1	O&M of the LIL[9]		N/A - Treat consistent with IFRS
		Fixed Fee		N/A - Treat consistent with IFRS
		Rent Payments	Cost Recovery of Operating Expenses to Administer LIL Limited Partnership	N/A - Treat consistent with IFRS
			LIL Capital Cost Recovery and Return	IFRS Deviation - Treat consistent with commercial payment
			LIL Sustaining Capital Recovery and Return	IFRS Deviation - Treat consistent with commercial payment
			Taxes	IFRS Deviation - Treat consistent with commercial payment
TFA[8]	3.1	O&M	Punch List Cost Deficiency	N/A - Treat consistent with IFRS
TFA[8]	3.1	O&M	Demobilization List Cost Deficiency	N/A - Treat consistent with IFRS

[1] Muskrat Falls Power Purchase Agreement ("Muskrat Falls PPA").

[2] International Financial Reporting Standards ("IFRS").

[3] Operation and Maintenance ("O&M").

[4] General Rate Application ("GRA").

[5] Impacts and Benefits Agreement ("IBA").

[6] Labrador Transmission Assets ("LTA").

[7] Under the IFRS, the recognition of the exports may not occur until the following period when actual exports are known. Under this circumstance, Newfoundland and Labrador Hydro ("Hydro") will recognize an IFRS deviation under IFRS 14 to ensure that an estimate of the exports is recorded in the period the export occurred.

[8] The timing of TFA payments are subject to Article 3.4, which could require Hydro to make a commercial payment in advance of the period the service was provided. The recognition of the commercial payment for regulatory purposes will be consistent the period in which the service was provided.

[9] Labrador-Island Link ("LIL").

Affidavit

N THE MATTER OF the *Electrical Power Control Act,* SNL 1994, Chapter E-5.1 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the "*Act*"), and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") pursuant to Section 58, 71, and 80 of the *Act*, for the approval of deferral accounts to address material changes in system costs as a result of the Muskrat Falls Project ("Project") and the phasing out of the Holyrood Thermal Generating Station ("Holyrood TGS") as a generating facility.

AFFIDAVIT

I, Kevin Fagan, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am the Vice President, Regulatory Affairs and Customer Service, for Newfoundland and Labrador Hydro, the Applicant named in the attached application.
2. I have read and understand the foregoing application.
3. To the best of my knowledge, information, and belief, all of the matters, facts, and things set out in this application are true.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador this 29th day of)
July, 2021, before me:)

Barrister – Newfoundland and Labrador

Kevin J. Fagan