NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD

IN THE MATTER OF the *Public Utilities Act*, R.S.N.W.T. 1988, c. 24 (Supp.), as amended;

AND IN THE MATTER OF the *Northwest Territories Power Corporation Act*, R.S.N.W.T. 1988, c. N-2, as amended;

AND IN THE MATTER OF the Northwest Territories Power Corporation's 2022/23 General Rate Application.

WRITTEN SUBMISSIONS OF THE NORTHWEST TERRITORIES POWER CORPORATION

November 18, 2022

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A. Introduction

1. On March 30, 2022, the Northwest Territories Power Corporation (the "Corporation" or "NTPC") filed with the Northwest Territories Public Utilities Board (the "Board" or "PUB") its 2022/23 General Rate Application (the "GRA" or "Application") setting out for the 2022/23 test year the forecast costs to supply its customers, revenues that would arise at existing rates, consequent shortfalls requiring changes to NTPC's rates and proposed rate changes to address those shortfalls.

2. NTPC prepared its Application to permit a simplified and expedited review by, among others, filing for a single test year and applying a zoned rate change approach to avoid the need for a Phase II application. The Board's approach to the Application similarly allowed for this GRA to proceed efficiently. That included the Board's directions resulting in a largely written process, together with a hybrid in-person/virtual oral hearing on limited topics. These measures resulted in an oral hearing occurring just over 5 months after filing of the GRA with the close of the record of the proceeding expected to occur approximately 8 months after filing. NTPC appreciates the Board's willingness to endorse an efficient, expedited process which at the same allows for a full adjudication of the issues.

3. The Corporation files this Written Argument in support of its Application. The Corporation does not intend to repeat its Application here. Rather it will address only certain items and issues raised by the interveners and/or the Board through the IR process, in evidence and in the oral proceeding.

4. Where the Corporation does not comment or address an item, it relies upon the evidence filed in support of the Application, including the oral evidence, information request responses, information provided at the technical meeting and other filings that form the record of this proceeding.

1. The Proceeding

5. In addition to filing the Application, NTPC also filed an Interim Rate Application seeking approval of the increases proposed in the Application effective as of May 1, 2022. Submissions were received from the Towns of Hay River and Fort Smith ("HR/FS"), and Stand Alone Energy Systems Ltd. ("SAES"). In its Decision 2-2022, the Board instead approved an across the board 2.5% rate increase for all zones. The Board was particularly concerned with whether the Corporation's disproportionate rate increases (described below), constituted rate rebalancing and thus were contrary to the GNWT 2017 Policy Directions. NTPC was instructed to seek direction from the GNWT on that point and that direction was ultimately received on September 6, 2022.[1] Given the Board did not approve NTPC's rates as requested, NTPC will be seeking to collect any shortfall between interim rates as the final approved rates as applicable.

6. In the context of the main Application, a number of interveners requested leave to intervene including HR/FS, the Town of Inuvik, Village of Fort Simpson and Town of Norman Wells (collectively the "Thermal Generation Communities" or "TGC"), Northland Utilities ("Northland") and SAES. On May 9, 2022, all of the interveners as well as the Board submitted

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[1] See para. 29 for further discussion of the response received from the GNWT.

information requests to NTPC. On June 13, 2022, NTPC filed responses to all information requests.

7. The Board subsequently sought and received submissions from all interveners on further process including the filing of intervener evidence, with areas of evidence if applicable, the need for an oral hearing, and public consultation. As a result, further process included the filing of intervener evidence and a round of IRs in relation to the intervener evidence. NTPC filed written rebuttal evidence on August 19, 2022. NTPC also filed updated GRA schedules on September 6, 2022.

8. Following further submissions, the Board determined that, while an oral hearing on the technical aspects of the Application would occur, attendance of interveners could be virtual. The Board further set two periods for public consultation. NTPC presented oral evidence at the hearing convened on September 8, 2022 in Yellowknife. The Corporation's panel of witnesses at the hearing included Paul Grant, Belinda Whitford, Charles (Chuck) Myles, and Andrew McLaren. NTPC did not cross-examine the interveners.

9. Following the close of the oral hearing, the Board held two public participation sessions, September 8, 2022 in the evening and September 9, 2022 in the morning. Both sessions provided for in-person and remote participation at locations across the NWT, specifically, Inuvik, Fort Smith and Norman Wells. Undertakings given during the oral hearing were answered on October 14, 2022 with a further round of IRs occurring. NTPC provided answers to those IRs on November 4, 2022.

10. HR/FS participated fully in the Application including submitting information requests, filing written evidence and responding to information requests from the Corporation and the Board. YK/HR cross-examined the NTPC panel.

11. TGC also participated in all aspects of the Application including submitting information requests, filing written evidence and responding to information requests from the Corporation and the Board. TGC also cross-examined the NTPC panel and submitted further IRs on responses to undertakings.

12. SAES participated fully in the process, submitting information requests, filing written evidence and cross-examining the NTPC panel. SAES also responded to IRs from the Corporation and the Board. NUL submitted information requests to the Corporation, but did not participate in the oral hearing or file written evidence.

2. Relief Requested

13. The Corporation respectfully requests the Board issue the following Order or Orders[2]:

[2] The amounts in this section have been updated based on the revised Schedules filed on September 6, 2022 that corrected minor errors or adjustments. PUB Ex. 2022-001-63 and 2022-001-63.1. For further details on changes, please refer to the schedules at Ex. 2022-001-63.1. For ease of reference throughout the balance of the written submission, NTPC has used the figures from the original Application filing unless otherwise noted.

1. Approving the Test Year Revenue Requirement of $122.550 million, including approval as required of the following costs and revenues:

a) Operating and Maintenance Expenses of $48.669 million for non-fuel operating expenses.

b) Fuel Expense of $27.412 million for fuel and purchased power expenses. Variances from fuel and purchased power prices approved as part of the GRA will be charged to or credited to NTPC's territory-wide Stabilization Fund.

c) Amortization Expense (net of government and customer contributions) of $27.223[3] million. Amortization expense is comprised of fixed asset amortization, fixed asset true-up and amortization of deferred charges. NTPC is seeking the following approvals:

i. To adopt new asset amortization rates as determined in NTPC's Depreciation Study performed by Concentric for all asset classes, as outlined in Chapter 6.

ii. To amortize all variances arising as a result of the new depreciation rates over the average remaining life of the respective asset class, with a minimum period of 5 years.

iii. To implement net salvage rates for future removal and site restoration in a phased approach.

iv. To decrease the annual appropriation for regulatory hearing costs from the $0.512 million per year level approved in the 2016-19 GRA, to $0.439 million per year.

v. To decrease the annual amortization of the normalized overhaul deferral account from an annual level of $3.759 million per year approved in the 2016-19 GRA to $2.538 million per year.

vi. To increase the annual amortization of the water licencing deferral account from an annual level of $1.511 million per year approved in the 2016-19 GRA to $2.569 million per year.

vii. To maintain the annual amortization of the reserve for injuries and damages account from an annual level of $0.250 million per year approved in the 2016-19 GRA.

viii. To increase the annual amortization of the employee future benefits account from an annual level of $0.500 million per year approved in the 2016-19 GRA to $0.609 million per year.

[3] As per Ex. 2022-001-63, updated to reflect addition of GNWT contribution for Inuvik 3rd LNG and Behchoko EV Charging Station project.

ix. Amortization of deferred expenses and feasibility studies as requested.

d) Return on Rate Base of $19.245[4] million, reflecting an underlying forecast capital structure financing Rate Base of approximately 41% equity and 59% long-term debt and capital lease, including the following proposed costs of capital:

i. Mid-Year Cost of Long-Term Debt of 4.46%.

ii. Mid-Year Cost of Capital Lease of 10.69%.

iii. A requested Return on Equity for all assets outside the Thermal Zone of 8.0%.

iv. An interest coverage ratio in the Thermal zone of 1.5.

2. Approving the Forecast Test Year Net Rate Base at $356.056[5] million reflecting the net book value of assets in service, government contributions, customer contributions, other deferred charges, and an allowance for working capital.

3. Approving an increase to the threshold for providing project business cases and summaries from $400,000 to $1 million.

4. Approving rates to be charged to customers covering the 2022-23 and 2023-24 fiscal years, as follows:

a) Snare Zone increases to energy rates by class as needed to achieve an average 2.5% increase in revenue from each class, in each of 2022-23 and 2023-24.

b) Thermal Zone increases to energy rates (except Norman Wells) by class as needed to achieve an average 2.5% increase in revenue from each class, in each of 2022-23 and 2023-24.

c) Norman Wells increases to energy rates by class as needed to achieve an average 10% increase in revenue from each class, in each of 2022-23 and 2023-24.

d) Taltson Zone increases to energy rates by class as needed to achieve an average 10% increase in revenue from each class, in each of 2022-23 and 2023-24. No changes are proposed to fixed monthly charges or demand charges.

14. NTPC is seeking the above approvals effective May 1, 2022.

[4] As per Ex. 2022-001-63, updated to reflect addition of GNWT contribution for Inuvik 3rd LNG and Behchoko EV Charging Station project.
[5] Updated as per Ex. 2022-001-63.1.

B. Background to the Application

1. The Board's Powers under the Public Utilities Act

15. The *Public Utilities Act* ("PU Act")[6] requires the Corporation to have its rates for electric service approved by the Board. The PU Act also governs the nature and scope of any such approval. Specifically:

(a) Section 49 requires the Board to determine a rate base for NTPC's property that is used or required to be used to provide service. It also requires the Board to consider the cost of the property at the time that property was first devoted to public use, the prudent acquisition cost to the public utility, less depreciation, amortization or depletion, and necessary working capital.

(b) Section 50 requires the Board to fix a fair return on NTPC's rate base.

(c) Subsection 51(2) requires the Board to fix just and reasonable rates and allows it to consider revenues and costs having regard to certain time periods.

(d) Subsection 51(3) requires the Board to fix proper and adequate depreciation or amortization rates for NTPC.

(e) Section 23 empowers the Board to grant a wide range of relief in respect of the Application.

16. Collectively, those provisions empower the Board to consider the various components of the Application and grant the relief requested by the Corporation.

2. Responding to Challenges Faced Since the 2016-18 GRA

17. NTPC has faced and continues to face a number of challenges that have arisen since the last GRA, challenges that could not have been foreseen. These include the COVID-19 pandemic that resulted in lost productivity due to work at home policies, increased contractor costs as a result of isolation, exemption and testing requirements, increased capital project costs when work ceased part way through projects and supply chain issues that continue to delay access to materials resulting in cascading scheduling delays and increased costs.

18. Over the past number of years, utilities across North America have faced increasing insurance costs as a result of often catastrophic industry wide events such as forest fires and floods. Further information in relation to these increased insurance costs are found at paras. 102 to 109 within.

19. Cyber-threats have become a significant concern for North American utilities in light of increasing cyber-threats. NTPC itself was the target of a cyber-threat, specifically a ransomware attack, in March of 2020, which resulted in significant lost productivity as functions such as vendor payment, project planning and engineering and data collection were impacted. In order to ensure

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[6] PU Act, R.S.N.W.T. 1988, c. 24 (Supp.).

the safety and reliability of its system, NTPC, like most other utilities, has increased its focus on information technology and security, which results in increased spending in the area and the addition of 3 FTEs to the IT department.

20. The impacts of increased environmental regulation are being felt across all industries and the utility industry is no exception. NTPC's water licence deferral account has been particularly impacted by increased regulation. Historical water licences and land use permits require renewal. However, renewal requirements have significantly increased based upon updated regulatory guidelines and frameworks which often require more details and frequent operational monitoring and reporting, additional environmental management and mitigation as well as more frequent and thorough stakeholder engagement.

21. At the same time as NTPC is facing these challenges head on, it is also embracing opportunities to achieve its strategic objectives of reducing costs and increasing sales to reduce the gap between the NWT and Canadian national average electricity rates. NTPC is also actively working to achieve the GNWT's greenhouse gas emissions reduction targets as outlined in the 2030 Energy Strategy.

22. NTPC has been able to offset pressures in the Thermal zone through increased contributions from renewable and lower cost generation sources including Liquified Natural Gas. NTPC also continues to pursue load growth opportunities in the Hydro zones and is working to implement efficiencies in controllable costs and rates. Accessing available GNWT and Federal funding for core infrastructure and capital expenditures allows NTPC to keep customer rates as low as possible while still allowing NTPC to ensure safe and reliable service. In addition, subsidized renewable projects like the Inuvik High Point wind turbine are providing benefits to customers in the current GRA through decreases in diesel consumption.

23. NTPC's application represents a measured and balanced approach recognizing the challenges facing customers as more particularly described below.

C. NTPC'S Rate Proposal

1. NTPC's Proposed Rates to address Longstanding Issues

24. As described above, NTPC has proposed zone rate adjustments with the goal being to address the longstanding issue of ensuring that each zone reasonably covers the costs of providing service in that zone. The approved Cost of Service results from the 2016-18 GRA result in the following ratios of Revenues to Costs ("RCC"):

(a) Snare Zone: 101.4%

(b) Taltson Zone: 87.0%

(c) Thermal Zone: 101.6%

Thus, the Taltson Zone shows under-collection compared to costs. And this under-collection is only exacerbated when taking into account NTPC's 2022-23 Revenue Requirement.

25. Table 1.2 of the Application,[7] applies the existing rates to the 2022-23 Revenue Requirement resulting in RCCs by zone as follows:

(a) Snare Zone: 94.7%

(b) Taltson Zone: 75.6%

(c) Thermal Zone: 91.9%

Not only would this result in a reduction in RCC across all zones, it would also result in a $10.629M shortfall.[8]

26. In light of the significant shortfall, and taking into account the resulting RCC rate for Taltson and the GNWT direction that Norman Wells is to be transitioned into the Thermal Zone, NTPC has proposed increases to energy rates by class as needed to achieve:

(a) in the Snare Zone, an average 2.5% increase in revenue from each class, in each of 2022-23 and 2023-24.

(b) in the Thermal Zone (except Norman Wells), an average 2.5% increase in revenue from each class, in each of 2022-23 and 2023-24.

(c) in Norman Wells, an average 10% increase in revenue from each class, in each of 2022-23 and 2023-24.

(d) in the Taltson Zone an average 10% increase in revenue from each class, in each of 2022-23 and 2023-24.

27. NTPC has not proposed and does not support across the board equal rate increases. The long standing inequities in RCC must be addressed. There is no ideal time to address those inequities, however, the RCC gap between zones only continues to widen with each GRA that the problem is not addressed.

(a) The Corporation's Proposal is Not Rate Rebalancing

28. NTPC is cognizant of the GNWT Rate Policy Direction from 2017 which prohibited Rate Rebalancing as part of a Phase II application outside of limited adjustments (no more than 1% per year for non-government customers). The current proposal does not represent "rebalancing" (i.e., raising one customer's rates so that other customers can see downward adjustments). The current proposal is merely aligning rates with costs, by zone, and has been proposed as an adjustment consistent with GNWT's rate policies as published. In all respects, NTPC's proposal continues to follow the GNWT rate directions set out in 2011, 2015 and 2017.

[7] Ex. 2022-001-001, Application, pdf p. 21, page 1-14.
[8] Note that the shortfall amount was updated in Ex. 2022-001-063 to $10.571M.

29. In Decision 2-2022, the Board directed NTPC to seek clarification from the GNWT as to the "applicability of [the GNWT] 2017 policy direction to the 2022-23 GRA and to any disproportionate rate increases for customer classes within each rate Zone."[9] The GNWT confirmed by letter dated September 6, 2022 that "[t]he 2017 Policy Direction was not intended to limit rate increases in a rate zones to 1% but to limit rebalancing for non-government customers to 1% and for government customers by 3% after cost of service changes are taken into account." The GNWT further confirmed that rate adjustments to maintain the Revenue to Cost Ratios do not constitute rebalancing. Finally, the GNWT reconfirmed the objective to "slowly move rate zones and customers into the previously directed range of reasonableness to ensure fairness and equity."[10]

(b) The Proposed Increases do not Result in Rate shock

30. HR/FS raised concerns that that proposed rate increases in the Taltson zone are likely to result in rate shock to residents and businesses.[11] NTPC disagrees with that suggestion.

31. The Board has previously approved rate increases of 10% or greater as being reasonable in the specific circumstances. Indeed, the Board in Decision 2-2007 recognized a 15% cap as a guide to "mitigate potential rate shock from the point of view of end use customers."[12] Mr. Myles confirmed in cross-examination that the Corporation viewed the 15% cap as a per year guideline to avoid rate shock. NTPC's proposal is within that guideline.[13]

32. Further, in assessing "rate shock" the PUB must take into account the circumstances before it. In the Application, as noted, NTPC is attempting to balance competing interests and give effect to the GWNT objective to move rate zones into the previously directed range of reasonableness to ensure fairness and equity. In these specific circumstance, NTPC views the 10% increase over two years, in the Taltson zone and for Norman Wells, does not constitute rate shock.[14]

(c) Managing the Resulting Shortfall

33. As noted in the Application, NTPC understands that approval of final rates as applied for would still leave a \$2.6M shortfall by the second year of the two year rate phase-in.

34. Despite that shortfall, NTPC believes that approval of the applied for revenue requirement and rates is nonetheless consistent with the requirements of the PU Act. NTPC notes that the PU Act specifies at section 50 that the Board "shall fix a fair return on the rate base of a public utility" while section 51 outlines the factors to be considered by the Board as it is tasked with fixing "just and reasonable rates".[15]

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[9] Decision 2-2022, NTPC 2022-23 GRA Interim Rate Application, pdf p. 8.
[10] Ex 2022-001-067, Letter from Minister Paulie Chinna dated September 6, 2022, pdf p. 2.
[11] Ex. 2022-001-036, Intervener Evidence of HR/FS, pdf p. 3.
[12] Ex. 2022-001-050, NTPC Rebuttal, pdf p. 13.
[13] Transcript 2022-23 NTPC GRA September 8, 2022, Hearing Session ("Transcripts"), pdf p. 91, ll. 8-10.
[14] Transcripts, pdf p. 90 line 22 to pdf p. 91 line 10.
[15] Ex. 2022-001-023, NTPC IR Responses, BR.NTPC-1(a), pdf p. 4.

35. NTPC's application requests that the Board approve what NTPC considers to be a fair return on rate base of 8%. NTPC also has applied for what it considers to be reasonable and just rates.

36. However, NTPC also understands that its request to set just and reasonable rates based on a two-step phase in process will likely result in NTPC failing to realize the fair return on equity fixed by the Board. As noted, NTPC has proposed a two-step phase in of rates which will result in two shortfalls as follows:

(a) In the test year, NTPC is only seeking the first step of a phase-in of rates. If NTPC is successful in its proposals, this stage would target revenue recovery of $114.126 million, which is $6.648 million below the test year revenue requirement required from rates of $120.810 million.[16]

(b) In the year beyond the test year (2023-24) NTPC is seeking the second step of a phase in of rates. This second step will yield $118.239 million. While 2023-24 is not a test year, and there is no revenue requirement being set for this year, the revenue to be generated is still $2.571 million below the 2022-23 revenue requirement.[17]

37. With respect to the shortfall in the test year, NTPC notes that a phase-in which was unlikely to recover the full ROE has been accepted by the Board in past GRA applications (including in the 2012-14 GRA and the 2016-2019 GRA) as appropriate and reasonable in the specific circumstances. NTPC notes that the Board was provided with confirmation from NTPC that safe and reliable service could be maintained notwithstanding the shortfalls. NTPC once again provides that same confirmation in relation to the anticipated shortfall in the current Application.

38. On the second type of shortfall, NTPC notes that this type of proposal has not been considered by the Board before. While the residual shortfall is not supported by any specific analysis outside the general expectation that substantial net savings from the proposed Inuvik wind development are anticipated in the year or two following the test year, NTPC submits that this proposal allows the Board to approve rates which are in the circumstances just and reasonable for all ratepayers.

39. NTPC submits that mathematically, in the absence of this approach, NTPC would need to increase its rate request by $2.571 million. This is approximately 2.5% of rate revenues from the communities not already capped at 10% in NTPC's proposal, with the result that the GRA rate proposal would become approximately 3.75%/3.75% for each of the two phase-in years for all Snare and Thermal communities (outside of Norman Wells), rather than the 2.5%/2.5% proposed in the GRA. As explained by Mr. McLaren during cross-examination, NTPC's application was prepared based on assessing whether the Corporation could absorb a $2.6M shortfall and still be in a position to provide safe and reliable service.[18] NTPC provided that assurance in its response to BR.NTPC-001. There is no evidence before the Board that the same assurance could be provided

[16] Figures have been updated for Sept. 6 filing, including the $0.058M reduction in total revenue requirement and the updated revenue requirement of $122.550M less other revenues of $1.740M.
[17] Updated for $0.058M reduction in revenue requirement.
[18] Transcripts, pdf pp. 93, l. 2 to pdf. p. 94 l. 6.

in the case of a larger shortfall. The alternative scenarios NTPC was asked to evaluate all result in the same approximate shortfall.

40. To be clear, NTPC is requesting the Board fix the fair return on equity at 8% based on, among others, the industry benchmarks, and in accordance with the requirement under the PU Act section 50(1). NTPC understands that it will likely fail to realize that fair rate of return, given the shortfalls proposed, but continues to support the proposed approach, with the full support of its shareholder, in these particular circumstances.

(d) Accounting for Wind Savings

41. In addition to phasing in rates over two years, NTPC also sought to minimize annual rate impacts on customers by including in the Application the substantial fuel savings benefits that are scheduled to arise in the Thermal zone from the installation of the Inuvik High Point Wind project. Although that project will not be fully commissioned within the 2022-23 Test Year, NTPC has reflected the costs saving in the current Application to allow customers to benefit as soon as possible from the investments being enabled by the substantial GNWT contributions to increasing clean renewable generation.[19]

42. In the course of the oral hearing, NTPC was asked to provide the source for the calculation of the Inuvik High Point Wind fuel savings. NTPC clarified that the $2.6M shortfall included in the Application is not the High Point Wind fuel savings. Rather it is the ultimate shortfall after accounting for anticipated gross fuel savings, that were initially estimated at $3M based on a diesel reduction potential of 10 GWh per year.[20]

43. NTPC continues to be prepared and able to absorb the $2.6M shortfall without compromising reliability and safety of service. However, at this time, it is unable to provide net fuel savings for the project as those savings will be impacted by the timing of the project's in-service date, as well as government contributions against the project's capital costs which are not yet finalized.[21]

2. The Alternative Rate Scenarios do not achieve the Objectives

(a) The PUB Alternative

44. During the oral hearing, the PUB requested that NTPC undertake to provide it with an alternative rate scenario which used the previous Cost of Service ("COS") study updated for the 2022-23 Revenue Requirement. NTPC provided that information in Tables 1 through 4 of the Undertaking 12 response.[22]

45. As outlined in Table 1[23] of the undertaking response, applying the existing interim rates to the updated COS analysis results in RCCs of:

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[19] Ex. 2022-001-001, Application, pdf p. 10.
[20] NTPC Undertaking Reponses, Undertaking 11, pdf p. 23.
[21] NTPC Undertaking Responses, Undertaking 11, pdf p. 23.
[22] NTPC Undertaking Responses, Undertaking 12, pdf pp. 25-28.
[23] NTPC Undertaking Responses, Undertaking 12, pdf p. 25.

(a) Snare zone: 97.0%

(b) Taltson zone: 78.2%

(c) Thermal zone: 94.2%

46. Applying the full rate increase to the updated COS analysis is set out in Table 2[24] and results in RCCs of:

(a) Snare zone: 99.5%

(b) Taltson zone: 92.3%

(c) Thermal zone: 97.8%

47. At the retail level, these adjustments result in RCCs for government and non-government classes of 74.0% and 115.8% respectively at existing interim rates and 78.4% and 120.8%, respectively, with the proposed full rate increase.[25]

48. In an IR in relation to Undertaking 12, the Board requested that NTPC provide information on an alternative scenario where RCC ratios were maintained at the level last approved by the Board and certain parameters were applied as outlined in BR.NTPC-11.

49. In order to provide that response, NTPC completed certain rate design steps:[26]

(a) All customer classes received increases to their energy rates to yield annual revenue increases of 3.8% per year (7.7% total over two years) which reflects the Corporate-wide general increase in revenue requirement.

(b) Increases of 1% per year to non-government customers and 3% per year to government customers were made to make progress toward the following rate design objectives:

(i) 90%-110% RCC target for the Taltson zone. Other zones were already within the 90-110% RCC target range.

(ii) Transitioning Norman Wells to the same rate levels as other Thermal Zone customers. Streetlighting rates in Norman Wells are already levelized with other communities in the Thermal Zone so no additional increases were applied for those customers.

(c) Rate decreases of 0.5% were applied to the remaining customer classes to yield the same total revenue proposed in NTPC's application.

[24] NTPC Undertaking Responses, Undertaking 12, pdf p. 26.
[25] NTPC Undertaking Responses, Undertaking 12, pdf pp. 27-28.
[26] NTPC IR Responses on Undertakings, BR.NTPC-11(a), pdf p. 5.

50. The results are set out below.[27]

	NTPC Prop RCC Per Und. 12	NTPC Prop RCC with Thermal Zone COS Adjusted for Requested	2018/19 Phase II Approved*	Alternative for Review
	A	B	C	D
Snare	99.5%	99.5%	101.4%	101.0%
Taltson	92.3%	92.3%	87.0%	83.8%
Thermal Excluding Norman Wells	100.5%	104.7%	106.0%	102.3%
Norman Wells (note 1)	79.5%	82.8%	71.0%	72.5%
Thermal Including Norman Wells	97.8%	101.9%	101.6%	98.5%
NTPC Total	97.9%	100.0%	100.0%	97.9%

51. NTPC notes that this "Alternative for Review" scenario results in RCC ratios for Taltson zone that are even further away from the 90-110% RCC target because the Taltson zone revenue requirement has increased by $1.3M or 11.1% since the prior GRA while in this scenario the revenues increase by only 7.0%. Specifically, the Taltson RCC ratio in at the 2018-19 GRA was 87.0%, while the proposed 2022-23 RCC would be 92.4%. In contrast, under the Board Alternative scenario, the RCC would be 83.8%.[28]

52. NTPC reiterates that its proposed rate increase addresses the longstanding issues of ensuring each zone reasonably covers the costs of providing service in that zone. Under NTPC's rate proposal each rate zone will be within 90%-110% RCC range targeted by the 2017 GNWT Rate Policy Direction.

53. Taltson zone costs will be increasing further in the future as the major Taltson Overhaul project is put into service. Without proper rate adjustments in the current application the Taltson zone cost recovery shortfall will continue to increase.

54. NTPC's proposed rates will bring Norman Wells rates closer to (but still below) the remainder of the Thermal zone and continue the transition to the Thermal zone Rates, as per the 2011 GNWT Rate Policy Guidelines.

55. The Alternative for Review scenario achieves the same revenue at the Corporate level as under NTPC's proposed rates by reducing the rate increase for Taltson Zone and Norman Wells

[27] NTPC IR Responses on Undertakings, BR.NTPC-11(a), pdf p. 6.
[28] NTPC IR Responses on Undertakings, BR.NTPC-11(a), pdf p. 7.

residential and general service customers and increasing rates for all other customers compared to NTPC's proposal. However, this scenario has several disadvantages:

(a) The Taltson zone RCC ratio remains below the 90-110% target range and erodes compared to the RCC ratio approved for the 2018-19 test year.

(b) Wholesale rates in Yellowknife require an additional 2% rate compared to NTPC's proposed rate increase. This would increase the TPSP reference rate and result in higher bill impacts to non-government residential customers eligible for the TPSP.

(b) The HR/FS Alternative

56. HR/FS, through an IR, also requested that NTPC provide an alternative rate scenario that included capping the Taltson zone RCC at 80% while allocating the unrecovered costs to the other zones.[29]

57. NTPC notes that capping the Taltson zone at 80% is outside the GNWT Rate Policy zonal target range of 90% to 110%. Nonetheless, NTPC provided the requested scenario. NTPC noted that capping the Taltson zone at 80% would mean rate increases in the Taltson zone of 3.0% per year, and rate increases in each of Snare and Thermal would see rate increases of 3.5% per year.[30]

58. That scenario results in the following RCCs:

	Snare	**Taltson**	**Thermal**	**Total**
RCC at Existing Rates	94.7%	75.6%	91.9%	91.2%
RCC with Taltson RCC Capped at 80%				
RCC at 1st year phase in	97.8%	77.9%	95.5%	94.4%
RCC at 2nd year phase in	101.0%	80.2%	99.2%	97.8%

59. The result of this scenario then is that not only would the Taltson zone have the lowest rate increase at 3.0% but it would also have the lowest RCC at 80.5% while the RCC in the Snare zone would be 101.0% and the Thermal zone RCC would be 99.2%. As with the PUB Alternative scenario, this does not achieve the objective of moving the Taltson zone into the previously directed range of reasonableness to ensure fairness and equity among customers.

60. In addition, NTPC is cognizant of the fact that the PU Act prohibits the charging of unduly preferential rates.[31] NTPC is concerned that continuing to delay the transition of Norman Wells into the Thermal zone and delay in moving the Taltson zone into the range of reasonableness will

[29] Ex. 2022-001-023, NTPC IR Responses, HR-FS.NTPC-3(a), pdf p. 70.
[30] NTPC assumed the Norman Wells rate increase of 10% remained unchanged for the purpose of the HR/FS scenario.
[31] PU Act, supra note 6, s. 48.

make it increasingly difficult to meet the PU Act test as these communities continue to fail to reach the RCC ratio and continue to be subsidized by customers in the Snare and Thermal zones.[32]

61. NTPC continues to request that the Board approve its rates as proposed in the Application.

D. Tariff, Sales and Revenues

1. 2022/23 GRA Forecasts

62. The 2022/23 Test Year sales forecast was prepared consistent with the methods reviewed by the Board in the 2016-19 GRA. Total forecast sales for 2022-2023 are slightly lower relative to the 2018-19 Test Year forecast with an average annual decline in sales of .1%. The decrease in total sales arises primarily in the Snare zone and Taltson zone with a small sales increase in the Thermal zone.

63. On the Snare system, most of the decreased sales are due to decreased sales to the wholesale customer, while the residential class is forecast to remain flat while sales to general service customers are forecast to be somewhat higher. In the Taltson zone, sales are forecast to be lower for residential, general services and streetlight customer classes while wholesale customers sales are forecast to remain flat in 2022-23 compared to 2018-19 forecasts. The Thermal zone sales are forecast lower for residential and streetlight customer classes. The decreases are offset by a higher general service sales forecast. Sales decreases for street lighting customers are due to the LED streetlight conversion.

64. Note that NTPC filed updated GRA schedules on September 6, 2022 including Schedules 5.1.1 to 5.1.3. Those schedules updated the allocation of other revenue based on sales forecast refinement that occurred prior to the filing of the Application. As noted in HR/FS.NTPC-12, the differences between the schedules is under $50,000 per zone.[33]

(a) NTPC's actual sales are tracking forecasts

65. While both SAES and HR/FS raised concerns with NTPC forecasts, NTPC stands behind its forecasts as reasonable and accurate. Indeed, during the oral hearing, NTPC gave two undertakings in response to questions from the Board specific to its forecasts as compared to actuals.[34]

66. NTPC was asked in Undertaking #9 to advise whether actual sales for Snare wholesale were tracking NTPC's forecast. NTPC confirmed that its actual sales year-to-date (April 1 to August 31, 2022) were slightly lower than forecast at 1.3% as outlined below.[35]

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[32] Ex. 2022-001-050, NTPC Rebuttal Evidence, pdf pp. 15-16.
[33] Ex. 2022-001-023, NTPC IR Responses, HR-FS.NTPC-12(a) and (b), pdf p. 96; Ex. 2022-001-63.1, NTPC Updated Schedules as of September 6, 2022.
[34] Transcripts, at pdf p. 110, ll. 13-17.
[35] NTPC Undertaking Responses, Undertaking 9, pdf p. 21.

Unit Sales (MWh)	2022-23 YTD Actuals	2022-23 YTD Budget	2022-23 YTD Variance	2022-23 YTD Variance %
Snare				
Wholesale Units	60,899	61,712	(813)	-1.3%

67. Similarly, in Undertaking #10, NTPC was asked to compare 2023 forecast sales with 2022-23 year-to-date and prior months actuals for all relevant rate classes.

68. The 2022-23 forecast sales comparison to actuals year-to-date (April 1 to August 31 2022) is set out below. Importantly, NTPC confirmed that overall, the actual sales are aligned with the NTPC's forecast across rate classes and zones. The only significant difference is in the Taltson wholesale year-to-date. This difference is related to the longer than anticipated shutdown of Taltson hydro plant (5 weeks vs. 3 weeks).[36]

Unit Sales (MWh)	2022-23 YTD Actuals	2022-23 YTD Budget	2022-23 YTD Variance	2022-23 YTD Variance %
Snare				
Industrial Units	2,465	2,525	(60)	-2.4%
Wholesale Units	60,899	61,712	(813)	-1.3%
Streetlight Units	34	34	(0)	0.0%
General Service Units	1,591	1,540	51	3.3%
Residential Units	1,737	1,696	41	2.4%
Snare Total	**66,726**	**67,507**	**(781)**	**-1.2%**
Taltson				
Wholesale Units	9,373	11,530	(2,157)	-18.7%
Streetlight Units	46	46	(0)	0.0%
General Service Units	4,797	4,650	147	3.2%
Residential Units	4,005	4,200	(194)	-4.6%
Taltson Total	**18,221**	**20,425**	**(2,204)**	**-10.8%**
Thermal				
Streetlight Units	197	197	0	0.1%
General Service Units	16,363	16,028	334	2.1%
Residential Units	10,314	10,102	213	2.1%
Thermal Total	**26,874**	**26,327**	**547**	**2.1%**
Total Unit Sales	**111,821**	**114,259**	**(2,438)**	**-2.1%**

[36] NTPC explained in response to BR.NTPC-12 (Ex. 2022-001-023, pdf p. 10) that it does not provide diesel back-up service to the Taltson wholesale customer. When the Taltson hydro generation is not available, the wholesale customer uses its own diesel generators. As a result, NTPC does not have sales to the Taltson wholesale customer when the Taltson hydro generation is unavailable.

69. NTPC's responses to Undertakings #9 and #10 clearly demonstrate the accuracy of NTPC's forecasts. Accordingly, the filing of further interim and unaudited information will not materially add anything to the Board's inquiry and NTPC urges the Board to reject the HR/FS recommendations in this regard.

70. SAES in its evidence, opined that NTPC's 2018-19 sales forecast was inflated and therefore there are doubts as to the accuracy of the cost of service analysis.[37] NTPC in its evidence outlined a number of problems with SAES' submission on this point including that differences between actual and forecast sales figures for a test year cannot impact the accuracy of a cost of service analysis, and further that the 2018-19 COS study was prepared based on the methodology reviewed and approved by the Board in Decision 8-2108.[38]

71. More importantly though, NTPC demonstrated that on a proper comparison of sales forecast to actuals in the Taltson zone (the zone of concern for SAES), the difference in sales ranged between 3.5% and 7% with the sales forecast difference at a zone level of only -0.3%.[39]

	Taltson Zone		
	2018-19 Forecast	**2018-19 Actual**	**Difference**
Residential	12,180	11,331	-7.0%
General Service	13,000	12,745	-2.0%
Wholesale	31,844	32,943	3.5%
Streetlights	260	114	56.0%
Total	**57,283**	**57,133**	**-0.3%**

(b) NTPC Sales Volumes

72. SAES also challenged NTPC to explain the lack of new markets over "the last 35 years" to address the fact that "Total sales have effectively been flat…"[40] In response NTPC outlined the ongoing challenge to develop large industrial customers as few mines have progressed to a stage of development which requires power in recent decades, and to date, all are located in areas where interconnection to the NWT transmission system has not been practical. NTPC confirmed it remains optimistic about a number of ongoing mining projects.[41]

[37] Ex. 2022-001-038, Intervener Evidence SAES Ltd, pdf p. 25.
[38] Ex. 2022-001-050, NTPC Rebuttal, pdf p. 21.
[39] Ex. 2022-001-050, NTPC Rebuttal, pdf pp. 21-22.
[40] Ex. 2022-001-013, SAES Ltd Information Requests to NTPC #1, pdf p. 1.
[41] Ex. 2022-001-023, NTPC IR Responses, SAES.NTPC-1(f), pdf p. 653.

73. NTPC also described how it has developed new markets for energy including, in the Taltson zone, which now has an interruptible electric heat rate that has several customers using the excess capacity for space heating. In addition, there are several communities where NTPC sells residual heat from electricity generation to provide space heating or water tempering. NTPC has also been active in promoting energy generation at mining sites since the diamond mines began.

74. NTPC continues to promote energy generation and has signed MOUs for several potential mining customers which are currently in development. NTPC has also sought to find markets for the excess capacity available in the Taltson hydro site including the development of a Hydrogen Generation rate in 1996 (which unfortunately found no customers), the current development of a transmission line to Fort Providence bringing hydro power to two diesel communities and will soon be making the interruptible electric heat rate available in Hay River. NTPC is also planning to install two EV charging stations in the current year.[42]

75. In light of the above, it is clear that NTPC is making great efforts to achieve its strategic goal of increasing sales to offset rate pressure and further, that NTPC has had success in that regard.

E. Revenue Requirement Matters

76. The Corporation's Revenue Requirement reflects the forecast cost of providing service in the Test Year including a return on equity in the two hydro zones and an interest coverage provision in the thermal zone, as detailed in Chapter 3 of the Application. The Revenue Requirement is recovered by way of rates charged for service to NTPC's retail, wholesale and industrial customers as well as non-electrical revenues.

77. The Corporation's revenue requirement has increased by $10.5M from the 2018-19 Test Year, resulting in a 2.3% per year on average increase.[43] As described in the Application, there are a number of drivers of the increased revenue requirement including aging infrastructure and increased asset management and preventative maintenance; inflation compared to lack of sales growth and increased production fuel costs; and requirements for enhanced information technology and security.[44]

78. The Corporation's Revenue Requirement is comprised of production fuel, operating and maintenance expenses, amortization and return on rate base. Details of the Corporation's calculation of its Revenue Requirement are found at chapters 4 to 7, and 11 of the Application. Specific components of the Revenue Requirement are discussed further in the following sections.

1. Fuel, Purchased Power and Generation

79. At chapter 4 of the Application, NTPC provided details of the methods used to prepare the forecasts for line losses and station service, generation, fuel efficiencies and fuel volumes and fuel prices. Chapter 4 of the Application also provided comparisons of the Test Year Forecasts with

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[42] Ex. 2022-001-023, NTPC IR Responses, SAES.NTPC-1(f), pdf p. 653.
[43] Ex. 2022-001-001, Application, pdf p. 64.
[44] Ex. 2022-001-001, Application, pdf pp. 65-67.

the 2018-19 GRA forecasts. At a summary level, line losses and service station forecasts are higher on both an absolute basis (30.7GWh in 2018-19 compared to 34.1 GWh in 2022-23) and as a percentage of total generation (9.2% in 2018-2019 compared to 10% in 2022-23).[45]

80. The Corporation's generation mix has changed compared to 2018-19 as a result of the natural gas ratio in Inuvik increasing from 40% to 60%. Further, total generation has increased by 5.0 GWh (1.5%) in part due to a change in disclosure of the generation related to interruptible heat sales in the forecast as well as the increase in line losses and station service as referred to above.[46]

81. Fuel efficiency as a whole has decreased by approximately 1.3% corporate wide. While there as a small increase in average fuel efficiencies in the Taltson zone, there was a small decrease in the Snare zone.[47]

82. In the Thermal zone, forecast diesel fuel efficiency has decreased by approximately 1.4%; this results in a net adverse effect on fuel expense of $0.25M. That impact is the result of changes in Inuvik, including less overall diesel generation (due to increased LNG generation) and lower efficiency diesel generation as a result of increased starts and stops and peaking use. While natural gas efficiency has also decreased in the Thermal zone, measuring efficiency on the basis of kWh/m3 is not as meaningful as the natural gas can vary in quality (measured in Gj/m3) much more than diesel. As NTPC is now importing LNG to Inuvik, some lower energy content gas has been delivered to NTPC in recent years and has resulted in the decreased efficiency analysis.[48]

83. Mr. Grant and Mr. Myles both spoke to fuel pricing during the oral hearing. The NTPC witnesses confirmed that the fuel price used in the Application was the actual price as of December of 2021. However, as Mr. Myles acknowledged, fuel prices have increased since the December 2021 pricing. At the time of the hearing, Mr. Myles gave evidence that they were substantially higher, specifically between 30 and 35 percent higher. However, Mr. Myles confirmed that no additional cost of fuel is built into the Application.[49] As Mr. Grant noted, the fuel stabilization fund is in place to deal with changes in price pressures on fuel.

2. Non-Production Fuel Operating and Maintenance Expenses

84. Chapter 5 of the Application sets out the forecasts for total operating and maintenance expenses for 2022-23. That included two new schedules directed to be included as a result of the MFR review and resulting Decision 9-2019: Schedule 5.4 providing common cost operating and maintenance expenses at account level, and Schedule 5.5 which reconciles the capitalized amount removed from the operating and maintenance expense and the amount charged to capital through the capitalized overhead pool account.[50]

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[45] Ex. 2022-001-001, Application, pdf p. 74.
[46] Ex. 2022-001-001, Application, pdf p. 77.
[47] Ex. 2022-001-001, Application, pdf p. 78.
[48] Ex. 2022-001-001, Application, pdf pp. 78-79.
[49] Transcripts, at pdf p. 113 l. 21 to pdf p. 114, l. 6.
[50] Ex. 2022-001-001, Application, pdf p. 86.

85. NTPC described in the Application the changes that have occurred in the O&M expenses which reflect the strategic initiatives undertaken by the Corporation. Those include legislative compliance, improvements to information technologies integration for capital work and inventory categorizing, capital program management, human resource policies, recruitment and retention, the succession planning program, operational analysis and reporting, SCADA system, hydro shutdown management and preventative maintenance.[51]

86. In the context of salaries and wages, and in advancing the strategic initiatives, the Corporation has added 16.25 FTE positions since the 2018-19 Test Year. In its Application, the Corporation described the added positions (20 in total) and the strategic reason for those positions well as the reduction in FTEs (3.75 net) resulting from a change in the Corporation's organizational structure.[52]

(a) NTPC's Capitalization Rate and Policy is reasonable and appropriate

87. The issue of internal labour capitalization policies was the subject of much of the TGC evidence. NTPC provided a complete response in its Rebuttal Evidence and responded to questions on that issue during the oral proceeding. The TGC, in its evidence, recommended that the PUB reduce NTPC's operating costs to account for its capitalization policies and estimated the impact of that reduction to be in the range of between $2.7M to $4.0M. NTPC urges the Board to reject the TGC recommendation. There is no compelling evidence to suggest that 25% is an appropriate labour capitalization rate[53] and even less so to suggest that the appropriate capitalization rate should be 29.16%.

88. NTPC noted several concerns with the TGC recommendations. First, those recommendations are calculated relying on an incorrect forecast of 16.1% for capitalized internal labour costs. As described in NTPC's rebuttal evidence, NTPC understands that calculation was done based on incorrect assumptions and inputs. NTPC's correct forecast capitalized internal labour costs for 2022-23 is 20.3% as described in Table 1 of the NTPC rebuttal not 16.1%.[54]

89. Second, the TGC recommendations rely upon a 25% and a 29.2% capitalization rate, based upon the comparables cited in the TGC evidence. NTPC disagrees that either rate is appropriate for NTPC's specific situation. As outlined in NTPC's rebuttal, NTPC's capitalization rate of 20.3% is reasonable and appropriate for a utility of its size and makeup and more critically is derived from the actual experience and time that is spent by various employees on capital project activities.

90. NTPC also noted in its evidence that its 20.3% capitalization of labour is comparable to NB Power Generation with a capitalization rate of 21.1%. While TGC's expert, Mr. Madsen believes that NB Power (with a capitalization rate of 29.2%) is a more appropriate comparator to NTPC, when asked during the oral proceeding, Mr. Myles reiterated that:

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[51] Ex. 2022-001-001, Application, pdf pp. 87-88.
[52] Ex. 2022-001-001, Application, pdf pp. 88-91.
[53] See Ex. 2022-001-037 TGC Intervener Evidence, pdf pp. 38-39.
[54] Ex. 2022-001-050, NTPC Rebuttal Evidence, pdf p. 3, A2.

> *In NTPC's opinion, … NB Power Generation would be closer aligned to NTPC. …NTPC does have a significant weight with respecting to generating assets as opposed to distribution where distribution primarily being with NUL in the Yellowknife area. And in the Snare zone, we are more heavily weighted in the generation side of the operation.*[55]

91. When Mr. Myles was questioned further on whether the comparison was "apples to apples" given that NTPC is a vertically integrated utility compared to NB Power Generation, Mr. Myles noted:

> *Looking at it from that perspective, it would not be apples to apples. Also I think it is important to look at the make-up of our capitalization, how we are capitalizing our direct labour cost. In relation to an NB Power, if you're looking at it from a vertically-integrated standpoint or just from a generation standpoint, I think it would be more important to look at the overall process of the -- of what labour is being capitalized and what is the methodology behind that labour being capitalized as opposed to strictly looking at it from a company to company comparison.*[56]

92. Mr. Madsen suggests that NTPC's capitalization rate should be higher because "NTPC is entering a heightened level of capital build over the next five years".[57] However, that is an overly broad assumption that does not always hold true. Time and effort spent will vary as a result of the complexity of the project or where new technology is included in a project, as opposed to varying purely based upon the dollar value of the capital program overall.

93. TGC's expert also seemingly contradicts his own position that it is most appropriate to compare NTPC's capitalization rate with other vertically integrated utilities, rather than single service investor-owned utilities. Contrary to that position, he relies heavily upon comparisons to AltaLink and ATCO Electric (both transmission focussed and investor-owned utilities). He further assumes that the AltaLink positions set out in his evidence perform the same function as at NTPC despite the fact that he has provided no job description for the AltaLink positions to understand if they are or are not performing the same work.[58]

94. NTPC notes that Mr. Madsen confirmed that higher capitalization rates over time will lead to the scenario where amortization and return costs are higher than current period O&M savings. Specifically, in response to BR.TGC-001, Mr. Madsen confirmed: "...ultimately the accumulation of capital costs will grow to a point where the return and amortization on the capital exceeds the annual savings in salaries."[59] In essence, a higher capitalization rate now pushes the issue off for future ratepayers. As such, this is only reasonable if the costs can be demonstrated to support capital projects, not simply as a way to reduce costs in the short term.

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[55] Transcripts, pdf p. 43, ll. 19-24.
[56] Transcripts, pdf p. 44, ll. 6-14.
[57] Ex. 2022-001-037 TGC Intervener Evidence, pdf p. 15.
[58] Ex. 2022-001-037 TGC Intervener Evidence, pdf pp. 27-29.
[59] Ex. 2022-001-044, TGC Responses to Board IRs, BR-TGC.001(a) pdf p. 2.

95. Finally, NTPC does not accept TGC's position regarding when work can be capitalized and specifically, Mr. Madsen's proposition that "if the work is necessary to ensure the asset can function as intended … then that work is capital in nature"[60] On TGC's definition, all maintenance functions would be considered capital in nature. For example:

(a) If an oil change is not completed, the engine will fail.

(b) If a damaged insulator is not replaced, then the connection point will fail.

(c) If snow is not cleared from the roads, employees cannot access the worksite and the assets will fail or not function in the way they were intended to function.

Maintenance is just that, intended to maintain the asset in working condition. Such work is not capital in nature and trying to capitalize such work would be contrary to NTPC's approach to capitalization under PSAS accounting.

96. As Mr. Myles referred to, and in accordance with PSAS accounting standards, NTPC's approach to capitalization of salaries is based on actual time spent by employees and is directly attributable to the construction or development activity. This includes technical and administrative work prior to the commencement of and during construction. When employees are working solely on a capital project, time is coded directly to that project. When employees are working on the capital program or on a number of different capital projects over a period of time, they code their time indirectly to the overhead account, which is then capitalized to the capital projects. Because NTPC relies on this cost causation basis for capitalizing salaries, NTPC's capitalization rate may not conform to the capitalization policies used by other utilities, which have different asset configurations, different use of employees and contractors to lead or support the capital program and different work environments and requirements.[61]

97. NTPC was asked to provide more information about its overhead policy in TGC.NTPC-10. As NTPC noted in its rebuttal evidence, it may not have clearly identified which positions are included in the "direct overhead" costs. Actual costs coded direct to overhead come from various divisions in a given year and are based on employees' work on capital projects or the capital program. The budget for the following year will be based on a percentage of historical time coded to the overhead project adjusted as required based on the estimated capital work for the upcoming year and how that may or may not change in alignment with the capital work. Time for employees coded to direct overhead costs include employees in accounting, treasury, customer service, regulatory, budgeting, supply chain management, information technology, and executive.[62]

98. NTPC does and will continue to review its internal labour capitalization budgets to ensure they continue to be reflective of its capital workloads as well as ensuring fair rates are charged to ratepayers and supporting intergenerational equity. If there is a gap between budgeting and workloads, NTPC will adjust at the time of the next GRA. NTPC confirms that the Human

[60] Ex.2022-001-037 TGC Intervener Evidence, pdf p. 32.
[61] Ex. 2022-001-050, NTPC Rebuttal, pdf pp. 5-6, A4.
[62] Ex. 2022-001-050, NTPC Rebuttal, pdf p. 5, A4.

Resources Division will be included in the review for overhead allocations in future budgeting processes.

99. Finally, NTPC notes that one objective of NTPC's strategic plan is to reduce the cost of power to customers. NTPC aims to do so based on achieving actual reduction in costs through improved efficiencies and innovation, rather than from shuffling the same costs between capital and OM costs as TGC proposes.

100. It is not sufficient to rely upon a list of utilities as suggested comparables or a list of capitalization rates for certain employee positions for an investor owned single service utility, as a basis to arbitrarily impose a different capitalization rate on NTPC. NTPC has provided compelling substantive evidence of its internal capitalization policy and practices in accordance with the applicable PSAS accounting standards.

101. NTPC does not simply apply across the board percentages to capital with no regard for how that time is actually spent.[63] It is not clear whether AltaLink approaches its capitalization in the same manner given that, for example, all accounting positions are at 61% regardless of whether the position is classified as operating or capital. NTPC capitalizes the actual time spent by employees that is directly attributable to the construction or development activity. That is evident by the additional detail provided in Tables 1 through 6 of NTPC's response to Undertaking 4. The percentage of time that is capitalized for the different functions varies widely among individuals within the group.[64] NTPC's capitalization rates are reflective of NTPC's employees own actual experience and are continually reviewed to ensure they remain reflective of the actual experience. In light of this substantive evidence, the TGC recommendations as to capitalization rates should be rejected.

(b) NTPC's Increased Insurance costs are Prudent

102. In the context of supplies and services, NTPC described in the Application that one driver of its increased revenue requirement was the increased costs of insurance. NTPC's insurance costs have increased $1.5M, "driven by a challenging insurance market for utilities driven by well-known industry-wide events such as fires and floods."[65] NTPC provided further details for the increased costs in response to an IR from TGC including describing the process by which it increased its deductible twice to reduce the impact of the rate increases.[66]

103. NTPC noted that in 2019 it suffered a loss, which together with a hardened insurance market, resulted in a rate increase of 37.5%. NTPC attempted to remarket the full insurance program but no competitive alternatives were available. NTPC chose to increase the property deductible from $300,000 to $1,000,000 to mitigate the full impact of this increase with the year-over-year rate increase of 35.7%. Contributing to the premium increase was an increase in insured values of 7.5%.

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[63] Ex. 2022-001-050, NTPC Rebuttal, pdf p. 5, A4.
[64] NTPC Responses to Undertaking, Undertaking 4, pdf pp. 7-10.
[65] Ex. 2022-001-001, Application, pdf p. 19.
[66] Ex. 2022-001-023, NTPC IR Responses, TGC.NTPC-11(a) iv), pdf pp. 779-780.

104. In 2020 the previous loss continued to increase, and the hard insurance market was fully developed. Property insurance rate increases were commonly above 50% on renewals with an adverse loss experience. On this renewal the year-over-year rate increase was 40.24%; however, NPTC thoroughly reviewed insured values and identified a reduction of 14% in values. Once again, NTPC elected to increase the deductible from $1,000,000 to $1,500,000. These two actions reduced the impact of rate increases to a 20% increase in premium.[67]

105. In 2021 the impact of the previous adverse claims experience had been largely priced into the rates; however, the hard market was still persisting with rate increases commonly in the 20% plus range. NTPC incurred, by comparison, a modest rate increase of 9.2%. With insured values rising by only 3.9% the overall increase in premium was 13.5%.

106. Working with its Broker AON, NTPC makes insurance buying decisions based on the financial impact loss could have on the organization. The decisions to increase deductibles, while impactful, would not threaten the financial stability of NTPC. Decisions with respect to reduction in limits or increased levels of self-insurance would, however, pose a significant risk to the organization. NTPC's ability to operate as a going concern would be impacted without dramatic increase in revenue to offset uninsured loss. This would particularly be the case if multiple losses were to occur in a policy period.

107. NTPC notes that TGC suggests an estimated reduction of $.7M could be obtained through increasing the deductible. NTPC notes that TGC's expert, Mr. Madsen is not an expert in the insurance market. By contrast, NTPC's Broker advisor, Ken McIssac, is an expert, with decades of insurance experience. As noted above, NTPC relies upon the expertise of Mr. McIsaac and others to advise as to the most appropriate insurance options, given the full understanding of NTPC's business, risk tolerance and loss history. Further, Mr. McIsaac and other advisors are compensated on a fixed fee contract and therefore their compensation is not tied to the amount of insurance placed.[68]

108. In responding to Undertaking 6, NTPC provided the advice received from Mr. McIsaac specific to the question of increasing the deductible. Mr. McIsaac advised that his expectation is "we would see a diminishing benefit to increasing deductibles beyond the current level of $1,500,000." To reiterate, NTPC has, with advice of the experts, already increased its deductible from $300,000 to $1M to $1.5M in the space of three years. On the advice of its experts, it does not view it to be a prudent course of action to increase the deductible any further.

109. Accordingly, NTPC requests that the Board reject the TGC recommendation that NTPC increase its insurance deductible.

(c) O&M and Capital Forecasts are Accurate

110. Mr. Bell in his evidence on behalf of HR/FS suggested that NTPC be required to file detailed copies of its operating and capital budgets with the Board each year in order to test NTPC's forecast accuracy.[69] In response to an IR from NTPC, Mr. Bell agreed that NTPC already

[67] Ex. 2022-001-023, NTPC IR Responses, TGC.NTPC-11(a) iv), pdf p. 780.
[68] Ex. 2022-001-050, NTPC Rebuttal, pdf p. 9, A8.
[69] Ex. 2022-001-036, Intervener Evidence HR/FS, pdf p. 24, A19.

provides an annual report of finance and operations and where there is an approved test year period, the approved forecast and actual results are provided. However, Mr. Bell maintained his recommendation that NTPC should provide an internal budget forecast for any year that does not have a test year forecast.[70]

111. In its rebuttal evidence, NTPC confirmed that it does not prepare operating budgets in non-GRA test years to the same level as for GRA test years. NTPC was concerned and remained concerned that Mr. Bell's recommendation would result in additional costs to the Corporation.

112. Mr. Myles was cross-examined by HR/FS counsel on this point during the oral hearing and explained that while NTPC does conduct internal reviews of its forecasts to actual results in non-GRA test years, those reviews have not gone through the level of detailed analysis and review process as is conducted for GRA test years.[71] In response to Undertaking #8, NTPC provided further information on the variance analyses and internal budget reviews that Mr. Myles discussed in his oral evidence.

113. NTPC confirmed that with respect to operations, prior to the 2022-23 fiscal year, NTPC conducted internal variance reviews on a quarterly and yearly basis. While NTPC provided an example of a quarterly variance review, it is important to note that the review was extracted from NTPC's unaudited and internal Q2 financial statements.[72] Accordingly, as Mr. Myles indicated in oral evidence, the information contained in the review has not been subject to the comprehensive review process that is conducted for GRA test years. Additional details in relation to some variance explanations may also be included in reports to the NTPC Board of Directors. However, not all variances will be addressed in those reports.

114. With respect to capital, capital spend throughout the year is tracked by division against the total yearly budgeted amount and is available as a summary table. Accordingly, the extract including at Attachment 3, Undertaking #8 shows only the spend in the particular quarter compared to the yearly budget. Again, while some variance explanations may be included in the NTPC Board of Directors report, those variance explanations are usually described by project, and not specified by division. As a result, the variance explanations may not clearly track back to the summary table.

115. NTPC noted in its response to Undertaking #8 that it had redacted irrelevant or confidential information from the Reports to the Board of Directors. Accordingly, as Mr. Myles and Mr. Grant explained would be the case in oral evidence,[73] additional work was required before the information and variance explanations could be disclosed in this Proceeding. Further, because the information is obtained from NTPC's unaudited and internal systems, it is not subject to the rigorous review process as the Test Year forecasts are. As such, NTPC has concerns in the Board or interveners relying too heavily on that information in assessing forecast accuracy and opposes any suggestion that this information should be provided as part of the MFR or otherwise with a GRA application.

[70] Ex. 2022-001-049, HR/FS Responses to NTPC Information Requests, NPTC.HR/FS-1(a), pdf p. 1.
[71] Transcripts, at pdf p. 97, ll. 15-19.
[72] Undertaking 8, pdf p. 15.
[73] Transcripts, at pdf p. 99, ll. 7-18 and pdf p. 100, ll. 1-12.

116. NTPC already files substantial information with the Board on an annual basis including the annual report of finances (comparing actual sales, revenues and expenses with the GRA test year forecasts, where applicable) and the prior year actuals and capital project budgets showing detailed capital spending forecasts by project. NTPC fully complies with the Standardized System of Accounts/Minimum Filing Requirements ("SSA/MFR") as approved by the PUB in Decision 12-2014, and as further reviewed in Decision 9-2019. If the Board is of the view that further information (including interim and/or unaudited information) will assist it in fully testing future GRA applications, NTPC urges the Board to initiate a SSA/MFR review and seek input from all interested parties as to the extent of that additional information.

3. Amortization Expense

(a) NTPC's Amortization/Depreciation Proposals are Reasonable and Appropriate

117. NTPC completed an amortization study for electric plant-in-service as at March 31, 2020 (the "Study").[74] NTPC has considered the results of the Study and the recommendations made by Concentric and finds them reasonable and appropriate. Accordingly, NTPC is proposing to implement the results of the Study for the 2022-23 Test Year.

118. In TGC's evidence, Mr. Madsen recommending adjusting the proposed depreciation rates for three accounts, Account 341; Account 342 and Account 343. NTPC does not agree with those recommendations.[75]

(i) Account 341 Diesel Plant – Structures and Improvements

119. Mr. Madsen recommends adjusting the proposed depreciation rates for Account 341from the proposed 35-S3 Iowa curve to a 40-S3 curve. NTPC disagrees with this recommendation. NTPC notes that the proposed increase in the Study, being an increase in life from 32 to 35 years is a 9.4% increase in the service life of this account. While a life extension is warranted, Concentric and NTPC do not agree that a 25% increase in service life (to 40 years) is warranted. This account has only seen retirements through to approximately 70 percent of the total exposures. As there have not yet been a large number of retirements seen, the actuarial analysis may change drastically in future depreciation studies. In the interest of gradualism and moderation, Concentric believes that the 35-S3 Iowa curve should be used for the depreciation calculations at this time with further life extensions examined in future depreciation studies.[76]

(ii) Account 342 Diesel Plant – Fuel Holders, Producers and Accessories

120. Mr. Madsen also recommends adjusting Account 342 from the proposed 27-R2 to either maintain the currently approved 30-L4 curve or alternatively a 35-R3 curve. Once again, NTPC and Concentric do not agree with that proposal. While Concentric agrees with Mr. Madsen's

[74] Ex. 2022-001-001, Application, Appendix A.
[75] Ex. 2022-001-037 TGC Intervener Evidence, pdf p. 67 l. 16 to pdf p. 68, l. 7.
[76] Ex. 2022-001-050, NTPC Rebuttal Evidence, pdf p. 7- 8.

comment that "… a review of the observed data shows relatively few retirements experienced for earlier vintages of assets beyond age 29.5. Comparatively, there is a higher degree of retirements in the age range of 7.5 to 24.5 years" [77] Concentric views this period of highest retirements as the area of the curve that it is most important to fit to. Only 2.4% of total retirements occur after the age of 35 years. The Iowa curve with a better fit through age 32.5 when 97.6% of the total retirements are observed is preferred. It is generally accepted in depreciation literature that the "knee", or area of greatest retirement activity, is most representative of the average service life expected for any group of assets.[78]

121. While previous depreciation studies had hoped for a life lengthening impact from the double walled tanks now in service, at this time the data has not supported this. Further, an average expected age of 30 years is in line with an average service life of 27 years, as it is expected that some of the old single walled tanks will still need to be replaced in the coming years. The expected engineering life of 30 years also does not take into account reasons for retirement other than the physical life of the assets – it is expected that the assets may be retired due to any number of other forces of retirement which will reduce the average service life of the entire account. A 27 year service life at this time allows for the retirement of any single walled tanks still in service, recognizes the historical retirement experience, and allows for interim retirements over the life of the double walled tanks.[79]

(iii) Account 343 Diesel Plant – Prime Movers

122. In regards to Account 343, Mr. Madsen recommends moving from the proposed 23-R3 curve to a 25-R3.5 curve. Concentric and NTPC emphasize that the retirements post age 22.5 (the section of the curve that Mr. Madsen is weighting most heavily) represent 11 million dollars, or 33% of the total retirements observed. Concentric placed a substantially higher degree of weighting on the 66% of retirements that occurred before this point as these make up the period of greatest retirement experience in arriving at its proposed adjustment.[80]

123. Mr. Madsen comments that the mathematical fit of the 25-R3.5 is superior to the 23-R3 recommended by Concentric. This is an expected outcome of the longer life. In accounts with "stub curves", or curves which do not show the entire life cycle of assets such as Account 343, it is very common for the lagging retirement transactions at the tail end of the curve to skew the residual measure calculation. This is due to the mathematical calculation performed in calculating the residual measure placing equal weighting on every year, which often results in curves with an inappropriately long life having a better residual measure than curves with an appropriate life through the area of greatest retirement activity.[81]

124. In light of the above, NTPC reiterates its request that the PUB approve NTPC's request to adopt new asset amortization rates as determined in NTPC's Depreciation Study performed by Concentric for all asset classes, as outlined in Chapter 6 of the Application.

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[77] Ex. 2022-001-037 TGC Intervener Evidence, pdf p. 74, ll. 10-12.
[78] Ex. 2022-001-050, NTPC Rebuttal Evidence, pdf p. 8.
[79] Ex. 2022-001-050, NTPC Rebuttal Evidence, pdf p. 8.
[80] Ex. 2022-001-050, NTPC Rebuttal Evidence, pdf p. 8.
[81] Ex. 2022-001-050, NTPC Rebuttal Evidence, pdf p. 8-9.

(b) There is no basis to change NTPC's Approach to Salvage

125. NTPC and its depreciation consultant remain of the view that net salvage is an important component of amortization rates. In 2016-19 GRA, while NTPC proposed to implement net salvage (following the "pause" then in place), at rates of one-quarter of the amount otherwise recommended, the Board approved a moderated phase-in approach to resuming net salvage recovery directing that only one-half of the NTPC recommended approach should be included for those test years. The 2020 Study continues to incorporate a phased in approach to net salvage and proposes limited adjustment to net salvage rates where required, notable below the levels indicated by the net salvage activity analysis.[82]

126. TGC's expert recommends that the Board "approve NTPC's applied for phase in of net salvage", and that he considers the "phased-in approach proposed by Concentric and NTPC at this time to be reasonable and a step in the right direction."[83] Mr. Madsen also considers the traditional approach as used by NPTC to be preferred. However, Mr. Madsen also goes on to opine on a number of alternative scenarios for the treatment of net salvage suggesting that those should be considered before an transition to the full transition back to a Traditional Approach.[84]

127. NTPC agrees the Traditional Approach is preferred and while there may be other theoretical or conceptual options, in NTPC's experience there are relatively few examples of these approaches being implemented for utilities in Canada. NTPC's experience appears consistent with the information provided by Mr. Madsen in response to NTPC.TGC-004. NTPC continues to support the use of the Traditional Approach.

4. Return on Rate Base

128. In keeping with the simplified approach and consistent with the previous Board approvals which considered the Alberta Utilities Commission (AUC) generic rate of return, NTPC proposes a return on equity (ROE) of 8.0% for the 2022-23 Test Year. NTPC is aware that the AUC recently approved an ROE of 8.5% for 2022. Despite that increase, NTPC is proposing to maintain its current ROE of 8.0% but advises that it may seek a higher return in the future that is more consistent with its peers.[85] For the Thermal zone the Corporation continues to apply the 1.5 interest coverage ratio in lieu of an ROE, in accordance with the GNWT guidelines. The Corporation's proposed capital structure for 2022-23 reflects the same mixture as approved for the 2018-19 Test Year of between 41% equity and 59% long term debt.[86]

F. Rate Base Matters

129. NTPC's Application at Chapter 11 describes its mid-year Rate Base for the 2022-23 Test Year. That includes the calculation of the gross plant in service, accumulated amortization,

[82] Ex. 2022-001-001, Application, pdf p. 121-122, pp 6-4 and 6-5.
[83] Ex. 2022-001-037 TGC Intervener Evidence, pdf p. 44. 43.
[84] Ex. 2022-001-037 TGC Intervener Evidence, pdf p 45, ll. 16-22
[85] Ex. 2022-001-001, Application, pdf p. 135.
[86] Ex. 2022-001-001, Application, pdf p. 137.

government and customer contributions and capital additions since the last GRA and in the Test Year.

130. NTPC outlined in some detail in Chapter 11 its capital planning process which supports the orderly replacement of aging infrastructure as well as providing effective management of NTPC assets on a Company wide basis.

131. Also in Chapter 11, NTPC summarized actual capital spending for the years 2018-19, 2019-20, and 2020-21 as well as providing forecasts for 2021-22 and 2022-23. In accordance with the PUB directives, NTPC has provided addition information for all projects over $400,000 through the inclusion of business cases.

1. NTPC conducts Asset Condition Assessments

132. In its review of those business cases, HR/FS identified a number of projects where it asserts that NTPC relied upon “end of life” as the basis for forecast capital expenditures.[87] HR/FS’s expert Mr. Bell suggests that NTPC “appears to have age in years as a driver related to end-of-life.” In his evidence, he references a number of projects where NTPC references the age of the assets and in IR responses, referred to the depreciation study anticipated life parameters of the particular account in which the assets reside.

133. Mr. Bell expresses his concern that end of life should be “based entirely on the condition of the assets and not just the physical age” and further that the Iowa curves should not be used to justify end of life.[88]

134. NTPC agrees with Mr. Bell that the condition of the assets is a critical piece of information in assessing whether assets have reached their end of life. However, NTPC confirmed in its rebuttal evidence that it was not justifying the replacement of the assets solely on asset vintage or age. Rather NTPC pointed to details as to the *asset condition* already on the record.[89]

135. For example,

(a) With respect to fuel tanks, as noted in the response to HR/FS.NTPC-24(b) insurance recommendations as well as best operating practice support NTPC converting its single walled tanks to double walled tanks. A spill can result in significant environmental damages and resulting costs which could far exceed costs to bring its single walled tanks up to current best practices now. Further, responding to a spill into secondary containment can also be a costly and resource demanding venture and NTPC views it as reasonable and prudent to take appropriate steps now to avoid such an event. These considerations support the measured replacement of single walled tanks prior to a catastrophic failure of the assets.[90]

[87] Ex. 2022-001-036, Intervener Evidence HR/FS, pdf pp. 7-9.
[88] Ex. 2022-001-036, Intervener Evidence HR/FS, pdf p. 10, A11.
[89] Ex. 2022-001-050 NTPC Rebuttal, pdf p. 12, A12.
[90] Ex. 2022-001-050 NTPC Rebuttal, pdf p. 12-13, A12.

(b) With respect to the Taltson Heavy Equipment purchase, the Corporation explained the existing equipment has become unreliable and expensive to maintain. Replacement parts are also becoming difficult to source. These factors beyond the simple age of the assets support the need for replacement assets.[91]

(c) With respect to the Inuvik EMD Ventilation Upgrade, the Corporation described that sections of the system are difficult to maintain due to a lack of available parts. The current roof mounted equipment and exhaust fans that control the plant temperature must be opened and closed manually. This manual process does not provide sufficient ventilation, which can negatively impact gen set reliability. In addition, there are safety concerns that must be mitigated and managed when operating manually controlled equipment at elevated heights. These factors beyond the simple age of the assets support the need to replace the existing assets.[92]

(d) With respect to the Gameti Plant G1 replacement, the Corporation outlined the existing reliability issues when the unit is in service. This factor in addition to the age of the unit supports replacing the existing asset at this time.[93]

(e) With respect to the Taltson Camp Upgrade, this project is a component of the larger project permit application for the Taltson Overhaul. The project permit for this project was approved in Decision 3-2022 which noted the Town of Hay River supported the approval of the project permit. The Corporation explained that the existing camp does not have enough capacity to accommodate all employees to complete normal annual plant maintenance or the overhaul projects, requiring six additional bedrooms to meet building code requirements. Currently, employees over the capacity of the camp must fly back to Fort Smith daily, a trip that adds significant cost for the Corporation and negatively impacts work efficiency. These factors contributed to the need for the camp upgrade.[94]

136. In Mr. Bell's evidence he refers to various approaches to asset health assessments, including predictive models, that are in use in Alberta. Ms. Whitford spoke to this point in cross-examination. Her evidence was that NTPC uses the term "end of life" not as a quantitative point in time for when an asset should be replaced but rather NTPC considers a number of things including:

(a) The age of the asset: … *it does matter if an asset is 40 years old or 10 years old. You'd expect the older assets maybe don't work as well. But we also consider things like functionality, whether an asset is working like it should be, working or not*;[95] and

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[91] Ex. 2022-001-050 NTPC Rebuttal, pdf p. 13, A12.
[92] Ex. 2022-001-050 NTPC Rebuttal, pdf p. 13, A12.
[93] Ex. 2022-001-050 NTPC Rebuttal, pdf p. 13, A12.
[94] Ex. 2022-001-050, NTPC Rebuttal, pdf p. 13, A12; Decision 3-2022, NTPC Taltson & Łutselk'e Project Permit Application, pdf pp. 11-12.
[95] Transcripts, at pdf p. 103, ll. 15-18.

(b) Technological obsolescence: *technologies are coming out, ... there is better equipment that's being created that provides better security over the environment or provides better fuel efficiency in our gen sets. And so it makes sense financially to -- or from an environmental steward's perspective to update or to replace our assets.*[96]

137. Ms. Whitford also described the Corporation's asset health assessment program that is new to the Corporation as having been underway in the last few years. Ms. Whitford described it as follows:

> *... every year we go out and assess a percentage of assets and have a look at their -- the condition of the assets. Are they as -- are they in the same condition that we would expect them to be in? Are they better? Are they worse? What do they look like? How are they operating?*[97]

138. Ms. Whitford confirmed that the assets condition assessments will not always be to the level of the Sachs Harbour condition assessment filed in the GRA. Rather, the plant operators inspect the assets, and the plant superintendents inspect the assets on a daily and weekly basis. In addition, there are the more in-depth asset assessments that would occur within the asset management program (discussed below). For a major replacement however, such as Sachs Harbour, NTPC may contract out for a formal condition assessment.[98]

139. Ms. Whitford described the Corporation's assets management framework, whereby the Corporation is looking at other important things, for example, in 2022, the Corporation is considering criticality. In other words, of the assets groups, which ones are the critical ones that the Corporation needs to focus on, because, for example, they will bring down an entire gen set or will create a problem with the plant functioning.[99] This assessment feeds into the prioritization of projects as is found in the five year capital plan.

140. However, Ms. Whitford also commented on the practicalities of Mr. Bell's proposed program:

> *So Mr. Bell talks about creating a very complex and -- and -- we'll call it expensive asset management program that I think is great for AltaLink. I don't know that that makes sense for our company. I mean, we are -- we are moving there. Not at the -- we're definitely not to the -- to the refinement that Mr. Bell proposes. And we're getting there, but we're not there.*[100]

141. Finally, Ms. Whitford also highlighted a critical distinction between NTPC and its operations versus AltaLink and that is the fact that NTPC operates in a very "extreme environment." It needs to provide safe reliable power for its customers in all conditions.[101]

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[96] Transcripts, at pdf p. 103, ll. 20-25.
[97] Transcripts, at pdf p. 104, ll. 6-9.
[98] Transcripts, at pdf p. 106, at l. 19 to pdf p.107 l. 3.
[99] Transcripts, at pdf p. 104, ll. 10-16.
[100] Transcripts, at pdf p. 104, ll. 20-25.
[101] Transcripts, at pdf p. 105, ll. 2-15.

That means in February, in Ulukhaktok, in Fort MacPherson, in Sachs Harbour. We need to make sure that -- that an engine doesn't break or doesn't fail because if it does, it may mean very costly repairs; it may mean extra time to get in there if there's a storm or we can't – we can't get in there to get to the community and address the failure, it may mean a number of days' delay in trying to get power back on.

So we have to balance all of these things about end of life or when an asset should be replaced with trying to provide safe, reliable power.

So all those considerations go into when it's time to replace an asset and also our asset health assessment.

142. NTPC notes that Mr. Bell's recommendation related to aging assets included that the Board require NTPC to provide "more than a cursory discussion of any asset management processes but instead provide a discussion of asset health, and risks of failure…" However, in light of Ms. Whitford's comprehensive evidence in relation to NTPC's asset health assessment program and asset management program, NTPC sees no benefit to a Board direction as to the "development of a comprehensive asset assessment methodology, either an Asset Health Assessment, a demerit system or a quantitative risk assessment…"[102] NTPC has already developed and implemented a comprehensive program as described by Ms. Whitford and expects the results of the program to better guide NTPC in its prioritization of replacements of assets in future.

G. Other Matters

1. Public Consultation Comments

143. The PUB scheduled two public consultation periods following the close of the technical portion of the hearing. Recognizing that the in-person hearing was being held in Yellowknife, the Board also directed NTPC to ensure that remote access was available for interested parties outside Yellowknife. NTPC worked with the PUB to create a registration process and put the appropriate technology in place to allow interested parties to appear at any of three satellite locations in each of Inuvik, Fort Smith and Norman Wells and be heard.

144. The public consultation occurred on September 8 and September 9, 2022. NPTC seated a panel consisting of Paul Grant, CFO, Erin Ladouceur, Director of Customer Service, and Doug Prendergast, Manager of Communications. NTPC was provided the opportunity to present an opening statement describing at a high level the GRA and the rationale underlying it. The NTPC representatives were then available to speak to questions.

[102] Ex. 2022-001-036, Intervener Evidence HR/FS, pdf p. 20.

145. NTPC appreciates the individuals who took time to attend the public consultation sessions. NTPC and the PUB heard from a number of individuals in Fort Smith,[103] both in person and remote, over the two public consultation sessions, as well as an individual from Norman Wells.[104]

146. NTPC heard the concerns expressed including over the proposed rate increases in the Taltson Zone and Norman Wells, frustrations over the lack of industrial customers, concerns regarding the Fort Smith distribution system, the rates charged in Fort Smith, use of surplus power from Taltson and the lack of a residential heat rate, among others.

147. NTPC recognizes the concerns raised on these important issues. As outlined in its opening statement at the public consultation, NTPC also recognizes that rate increases cannot be the only solution to the challenges facing the electricity sector in the NWT. NTPC recognizes that customers need to see balanced efforts and a plan for the future in order to increase their confidence in NTPC's ability to deliver electricity safely and reliably. Further NTPC is continuing to make progress on its strategic plan that aims to reduce the gap between electricity rates in the NWT and the Canadian national average while at the same time achieving the 25% reduction in GHG emissions targeted for electricity generation in the GNWT's 2030 Energy Strategy.

148. NTPC has made its best efforts to put forth an Application that will move it closer to these goals in a reasonable and measured manner.

H. Conclusion

149. This Written Submission sets out the reasons and support for the Corporation's 2022-23 GRA. The costs, revenues at existing rates, and resulting shortfall is based on prudent and reasonable forecasts of NTPC's expected operations over the test year.

[103] Transcripts 2022-23 NTPC GRA September 8, 2022 Public Consultation Session, pdf p. 2, and Transcripts 2022-23 NTPC GRA September 9, 2022, Public Consultation Session, pdf p. 2 and within: From Fort Smith: Carl Cox; Don Jaque; Thebacha MLA Frieda Martselos; David Poitras, Chief of Salt River First Nation; Allan Heron, President Fort Smith Métis Council; Fred Daniels, Mayor Town of Fort Smith, Dianna Korol, Councillor Town of Fort Smith; Diane Seals, and Thaidene Paulette, Chief Smith's Landing First Nation.

[104] Transcripts 2022-23 NTPC GRA September 9, 2022, Public Consultation Session, pdf p. 2 and within: Susan Wright, North-Wright Airways.

150. The Corporation is fully aware of the pressures on customers and heard the concerns raised during the public consultation sessions and as advanced in correspondence submitted to the Board in advance of the hearing. The Corporation fully understands the depth of those concerns and the impact on customers, including those in the Taltson zone and Norman Wells, of any rate hike. The Corporation has worked to achieve what it believes is an appropriate balance of competing concerns in the current Application. Approval of the requested Revenue Requirement and Rate Base balances and Rate proposals will allow the Corporation to continue to provide safe and reliable service to the Northwest Territories.

151. Accordingly, NTPC respectfully requests that the Board approve the Corporation's 2022-23 GRA Application and grant the requested relief set out in section A.2 above.

ALL OF WHICH is respectfully submitted this 18th day of November, 2022.

Borden Ladner Gervais LLP,
Counsel for the Northwest Territories
Power Corporation

"*Original Signed by Karen Salmon*"
Karen A. Salmon