

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 2006/07 and 2007/08 Phase I General Rate
Application.

**WRITTEN ARGUMENT OF
THE NORTHWEST TERRITORIES POWER
CORPORATION**

June 18, 2007

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1 **1. Introduction**

2 On November 24, 2006 the Northwest Territories Power Corporation (the “Corporation” or
3 “NTPC”) filed with the Northwest Territories Public Utilities Board (the “Board” or “PUB”) its
4 2006/08 Phase I General Rate Application (“GRA”) setting out for the 2006/07 and 2007/08 test
5 years the forecast costs to supply its customers, revenues that would arise at existing rates and
6 consequent shortfall requiring changes to NTPC’s rates (the “Application”).

7 The Corporation supplemented the Application with a number of filings, including responses to
8 interrogatories and rebuttal evidence, and presented oral evidence at the hearing convened on
9 May 23 to 25, 2007 in Yellowknife. The Corporation’s witnesses at the hearing were presented
10 in two panels:

- 11 (i) Capital and Operations Panel comprised of Ms. Judy Goucher, Mr. Stephen Kerr,
12 Mr. John Locke, Mr. Terrence Courtoreille and Mr. Patrick Bowman; and
- 13 (ii) Rate of Return and Capital Structure Panel comprised of Ms. Goucher, Mr.
14 Bowman and Ms. Kathleen McShane.

15 The City of Yellowknife and the Towns of Hay River and Fort Smith (collectively the “Hydro
16 Communities” or “HC”) participated by filing written evidence and responses to interrogatories,
17 and presenting the oral evidence of Dr. Lawrence Kryzanowski. The communities of Fort Liard,
18 Fort Simpson and Inuvik (collectively the “Thermal Generation Communities” or “TGC”) also
19 participated by filing written evidence and responses to interrogatories, and presenting oral
20 evidence from Mr. Azad Merani.

21 Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited (collectively
22 “NUL”), as well as the Behdzi Ahda First Nation, posed information requests to the Corporation
23 and appeared at the hearing, but did not cross-examine or present witnesses.

24 The Dogrib Power Corporation (“DPC”) made an oral presentation at the hearing On June 24,
25 2007. The DPC was represented by Mr. Dan Marion, of the DPC, and Mr. Jeff Baker from
26 PricewaterhouseCoopers, the DPC’s auditors. Mr. Baker followed up by filing a written copy of
27 his presentation with the Board by email dated May 30, 2007.

28 Mr. David Wind, a citizen of Yellowknife, made a presentation at the hearing on June 25, 2007.

29 The Community of Behchoko filed a written submission dated May 22, 2007 (the “Behchoko
30 Submission”).

31 Norman Yakeleya, MLA, Sahtu, posed information requests to the Corporation dated December
32 15, 2006.

33 **(a) Requested Relief**

34 The Corporation respectfully requests the Board to issue the following Order or Orders:¹

¹ See Ex. 13, pp. 4-8.

- 1 1. Approving the 2006/07 and 2007/08 Revenue Requirement at \$79.779 million and
2 \$84.203 million in 2006/07 and 2007/08 respectively,² including approval as required of
3 the following costs and revenues:
- 4 a. Operating and Maintenance Expenses of \$30.984 million and \$32.444 million for
5 non-fuel expenses in 2006/07 and 2007/08 respectively (see section 4(a) below),
6 plus \$16.639 million and \$17.423 million for production fuel expenses in 2006/07
7 and 2007/08 respectively (see section 4(b) below), including approvals:
- 8 (i) to establish fuel prices at forecast levels for the two test years, with actual
9 variances from forecast being charged to or credited to NTPC's Fuel
10 Stabilization Funds (see section 8(b) below); and
- 11 (ii) to set the annual appropriation to the Reserve for Injuries and Damages at
12 \$0.670 million (see section 4(e)(i) below).
- 13 b. Amortization Expenses (net of customer contributions) of \$9.568 million and
14 \$10.115 million in 2006/07 and 2007/08 respectively for fixed assets (see section
15 4(c) below), plus \$2.502 million in each test year for other amortization (see
16 section 4(d) below), including approvals:
- 17 (i) to set the annual appropriation for regulatory hearing costs at \$0.600
18 million (see section 4(d)(ii) below);
- 19 (ii) to set the annual appropriation for overhauls at \$1.693 million (see section
20 4(d)(i) below); and
- 21 (iii) to establish a new water licensing deferral account with an annual
22 appropriation of \$0.137 million (see section 4(d)(iii) below).
- 23 c. Return on Rate Base of \$20.190 million and \$21.822 million in 2006/07 and
24 2007/08 respectively, reflecting an underlying forecast capital structure of
25 approximately 45% long-term debt, 11% capital lease, -1% no-cost capital and
26 46% equity in 2006/07, and 42% long-term debt, 11% capital lease, -1% no cost
27 capital and 49% equity in 2007/08, and reflecting the results of NTPC's recent
28 review of fair return on equity at 10.50% for 2006/07 and 10.75% for 2007/08
29 (see section 4(f) below).
- 30 2. Approving the forecast 2006/07 and 2007/08 Rate Base at \$191.879 million and
31 \$201.992 million in 2006/07 and 2007/08 respectively, reflecting the net book value of
32 assets in service, customer contributions, other deferred charges, and an allowance for
33 working capital, including the following capital projects that have already been reviewed
34 and approved by the Board:

² The stated revenue requirement is calculated prior to making a required adjustment for line losses in Norman Wells, which will be reflected in the Corporation's re-filing following the Board's decision on this Application. See section 10(b) below.

- 1 a. Bluefish Generating Station in 2004/05, at \$11.861 million plus other capital
2 works completed to the end of 2004/05 (see section 6(a)(i) below);
- 3 b. Fort McPherson Power Plant in 2004/05 and 2005/06 at \$7.996 million less
4 insurance proceeds of \$5.085 million (see section 6(a)(ii) below);
- 5 c. Snare Rapids Plant upgrade in 2005/06 at \$3.838 million and further amounts in
6 2007/08 at \$1.305 million for a total \$5.143 million (see section 6(a)(iii) below);
- 7 d. L199 recommissioning amounts at a net cost of \$3.068 million (see section
8 6(a)(iv) below); and
- 9 e. Aklavik Power Plant in 2007/08 at \$5.298 million (see section 6(a)(v) below).
- 10 3. Approving revised Terms and Conditions of Service (see section 7 below).
- 11 4. Approving revised Maximum Corporation Investment levels of \$1,500 per residence,
12 \$750/unit for multiple unit residential dwellings and \$250/anticipated kW for General
13 Service customers (see section 7(e) below).
- 14 5. Approving the Standby Interconnection Guidelines proposed to be applicable to any
15 customer who seeks to receive standby service or otherwise self-generate all or a portion
16 of their power while connected to NTPC's distribution system (see section 8(a) below).
- 17 6. Stabilization Funds: NTPC is proposing to continue and maintain its fuel and water
18 stabilization funds, all as active funds. This includes five fuel stabilization funds
19 (Norman Wells, Inuvik, Taltson, Snare-Yellowknife and Diesel communities) and two
20 water stabilization funds (Snare-Yellowknife and Taltson). The variables used in the
21 calculation of the fuel and water stabilization funds will be updated to incorporate the
22 fuel prices, efficiencies and quantities of fuel, by community, for 2006/07 and 2007/08 as
23 set out in Schedules 3.3.1 and 3.3.2 of Exhibit 13 (see section 8(b) below).
- 24 7. Accounting Provisions: NTPC seeks approval and confirmation from the PUB to
25 maintain its regulatory accounts as per established practice (see section 8(c) below).

26 **2. Background**

27 **(a) The Board's Powers under the *Public Utilities Act***

28 The *Public Utilities Act*³ ("*PU Act*") requires the Corporation to have its rates for electric service
29 be approved by the Board and governs nature and scope of any such approval. Specifically:

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

³ R.S.N.W.T. 1988, c. 24 (Supp.).

- 1 • Section 50 requires the Board to fix a fair return on NTPC's rate base.
- 2 • Subsection 51(2) requires the Board to fix just and reasonable rates and allows it to consider
3 revenues and costs having regard to certain time periods.
- 4 • Subsection 51(3) requires the Board to fix proper and adequate depreciation or amortization
5 rates for NTPC.
- 6 • Section 63 requires NTPC to seek approval from the Board of its Terms and Conditions of
7 Service.
- 8 • Section 23 empowers the Board it grant a wide range of relief in respect of the Application.

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

11 **(b) The Corporation's Operating Environment and Material Developments since**
12 **the 2001/03 GRA**

13 In considering the various components of the Application and exercise of the Board's powers set
14 out in section 2(a) above, it is imperative to keep in mind the Corporation's operating
15 environment and material developments faced by NTPC since its last GRA in 2001/03. Ms.
16 Goucher highlighted those factors in her opening statement.

17 As the main generator and transmitter of power in the Northwest Territories,
18 NTPC faces many unique challenges to providing safe and reliable electric
19 service. NTPC operates in a unique environment. We have extremely low
20 customer densities, the weather is extreme, mostly to the cold end and we have a
21 number of logistical challenges that we must deal with, in addition to the lack of
22 an integrated transmission system. This sets the Corporation apart from most
23 utilities.

24 The unique environment that we operate in has a profound impact on our
25 operations throughout our service area and is inescapably reflected in this
26 application. NTPC serves a population of approximately 43 thousand people
27 spread across an area of 1.3 million square kilometres.

28 Seventy-five (75) percent of our generation is from hydro, a renewable resource.
29 We supply hydro to wholesale customers; Northland Utilities Yellowknife
30 Limited and Northland Utilities NWT Limited in Hay River and surrounding area.
31 Hydro Power also serves the Corporation's industrial customers, albeit at
32 significantly reduced levels from prior years, and that being Miramar Con Mine
33 and the former Giant Mine, both in the Yellowknife area.

34 NTPC provides generation and distribution services to residents in twenty-five
35 (25) communities. Nineteen (19) of those are served by diesel generation, two (2)
36 are served by other generation sources, priced relative to diesel prices, and the
37 remaining four (4) communities are served by hydro generation.

1 While total electrical load is approximately 65 megawatts, that load is served by
2 an array of discrete systems ranging from isolated power systems with generating
3 capacity of 240 kilowatts in Colville Lake, to the integrated Snare Yellowknife
4 system of -- with a 65-megawatt installed capacity. The Corporation's total
5 install capacity is just over 126 megawatts.

6 As these systems are isolated and unconnected, each must be planned for
7 independently.⁴

8 Ms. Goucher then went on to describe the material changes affecting the Corporation since the
9 2001/03 GRA.

10 Mr. Chairman, most notably these are: dramatic increases to the price of diesel
11 fuel; the planned end to the credits to customers in both amortization, insurance,
12 and the pension revenues from the territorial government; increased regulation
13 and tight labour and contractor markets; and inflation, which has exceeded the
14 pace of sales growth in the Corporation.⁵

15 Where possible, the Corporation has taken prudent and proactive measures to address rising
16 diesel fuel prices.

17 NTPC's efforts over the long term to minimize the impact of diesel cost increases
18 include increasing the use of hydro generation through Aboriginal joint venture
19 development of the Snare/Cascades Hydro with the Dogrib, and also through the
20 purchase of the Bluefish Hydro Facility from Miramar Con.

21 NTPC has also increased its natural gas generation by installing a total of three (3)
22 natural gas gen sets in Inuvik and by purchasing natural gas generated power in
23 Norman Wells.

24 Our continuing efforts have improved diesel generation efficiency rates in isolated
25 diesel communities by almost 2.6 percent since the last General Rate Application.

26 Lastly, we've entered into a fuel supply agreement with the Territorial Petroleum
27 Products Division for almost all of our fuel purchasing, handling and storage
28 requirements which reduces our future environmental liability exposure and also
29 allows the Corporation to concentrate its limited resources in other areas of
30 operations.

31 Long term, we're working together to have joint tankage facilities which will be a
32 savings to customers in the years to come.⁶

33 Regarding the planned end of credits to customers for amortization, insurance and the pension
34 revenues from the Government of the Northwest Territories ("GNWT"), the Corporation had

⁴ Tr. I, p. 39, ln. 14 to p. 41, ln. 3.

⁵ Tr. I, p. 41, lns. 6-12.

⁶ Tr. I, p. 41, ln. 23 to p. 42, ln. 21.

1 previously identified the temporary nature of those credits when approved by the Board and now
2 incorporates the costs associated with their termination into the Application.⁷

3 Increased regulatory requirements relating to changes to safety, environment, human rights,
4 access to information and fuel facility regulations have driven increases in both human and
5 financial resources since the last GRA. As noted by Ms. Goucher, “[t]hese cost increases are not
6 avoidable, as NTPC is required to maintain safe and reliable service.”⁸

7 With respect to the extremely tight skilled and professional labour and contractor markets,
8 “NTPC has developed a number of measures including its linemen, electrical, and mechanical
9 apprenticeship programs as pro-active northern approaches to [address] this challenge.”⁹

10 Lastly, the Corporation has experienced inflation of 2% to 3% per annum or 8% to 12% since the
11 last GRA. In contrast, NTPC’s loads in most cases are flat or have dropped substantially. For
12 example, industrial sales on the Snare/Yellowknife System are forecasted to decrease by
13 approximately 30% as compared to the 2002/03 test year.¹⁰ Ms. Goucher described the
14 challenge faced by NTPC: “[a] direct result of negative or stagnant load growth is that there is
15 no corresponding revenue growth to offset inflationary cost pressures.”¹¹ She also went on to
16 discuss the Corporation’s efforts to combat inflation notwithstanding negative or stagnant load
17 growth.

18 ...[T]he Corporation has undertaken a number of internal cost mitigation
19 measures including steps to minimize travel and accommodation costs through the
20 coordination of training activities and the use of video conferencing, reduction of
21 overtime, implementation of plant automation, and filling vacant positions as
22 quickly as possible to mitigate the use of contractors, if we are able to acquire
23 them at all, and the use of overtime in the event that a position goes unfilled for
24 any length of time. The Corporation has also reduced staff positions by ten (10)
25 since the 2001/03 General Rate Application.

26 Those staff reductions occurred notwithstanding the addition of positions required
27 to address the increase in regulatory requirements and the apprenticeship
28 programs...¹²

29 The Corporation is very aware of how increases to the cost of electric power may impact its
30 customers. To that end the Corporation has implemented a number of programs to help
31 customers manage their own energy consumption and minimize the impacts on their bills. Those
32 programs include residential and general service energy audits, streetlight change-outs to more
33 efficient lights and distribution monthly customer information packages regarding household
34 energy consumption and understanding demand charges, and a new bill format that provides

⁷ Tr. I, p. 42, ln. 22 to p. 43, ln. 3.

⁸ Tr. I, p. 43, lns. 8-13; Ex. 19, NTPC Opening Statement, p. 3, lns. 27-29.

⁹ Tr. I, p. 43, lns. 17-20.

¹⁰ Tr. I, p. 43, ln. 21 to p. 44, ln. 2.

¹¹ Tr. I, p. 44, lns. 7-9.

¹² Tr. I, p. 44, lns. 10-25.

1 energy consumption information.¹³ “In the Corporation’s view, customer education regarding
2 end-use measures to reduce consumption is the best and most direct way to lower electricity
3 bills.”¹⁴

4 To encourage stakeholder participation and answer questions about the required rate increase, the
5 Corporation conducted a comprehensive stakeholder consultation program, which included
6 providing written materials summarizing and explaining the cost drivers, meeting with the
7 majority of directly served communities, Territorial MLAs and media, and hosting a Technical
8 Workshop for interested parties and the Board’s consultant.¹⁵

9 **(c) Scope of the Application with Respect to Extraordinary Risks and Events**

10 In preparing the Application, it became clear that two matters – new industrial load and climate
11 change regulation – could materially affect the Corporation’s operations going forward.
12 Unfortunately, the lack of any certainty relating to those matters precluded any meaningful
13 attempt to account for potential impacts in the Application. Ms. Goucher addressed both
14 extraordinary risks and events in her opening statement.

15 Mr. Chairman, a number of key events may arise in the future that are beyond the
16 scope or – or the ability of NTPC to forecast at this time, however, at this time
17 major new industrial customers arising sooner than expected and the
18 implementation of climate change regulation are two (2) that we’ve identified as
19 extraordinary risks and contingencies that are not addressed in -- in this
20 application. In the event that such events materialize, NTPC may require a
21 further review and Board decision.¹⁶

22 Mr. Bowman clarified that “...new mining loads, at this time, are not -- are not something NTPC
23 is able to forecast in terms of timing, duration, size, likelihood and as a result, they have not been
24 included in the test years. The chances of them opening the test years are slim to nil.”¹⁷ He also
25 noted that even if such a load did materialize, NTPC would have to be back before the Board as
26 it does not currently have an approved rate in place to serve such a load.¹⁸

27 Mr. Kerr described the uncertainty regarding climate change regulation as “...trying to hit a
28 moving target. There’s been a number of plans come into place based on the various
29 governments that have been in place at the time.”¹⁹ Then, in response to the TGC’s consultant,
30 Mr. Kerr concluded:

31 I guess without the exact details of the program that are being proposed by the
32 Federal Government, we’re not exactly sure where this is going to all shake out.

¹³ Tr. I, p. 45, lns. 1-23.

¹⁴ Tr. I, p. 45, lns. 13-16.

¹⁵ Tr. I, p. 38, lns. 8-25.

¹⁶ Tr. I, p. 45, ln. 24 to p. 46, ln. 8.

¹⁷ Tr. I, p. 63, lns. 14-17.

¹⁸ Tr. I, p. 63, ln. 22 to p. 64, ln. 2.

¹⁹ Tr. I, p. 21, lns. 15-17; see also Tr. I, pp. 21-25 and pp. 28-29.

1 Whether this will cost money for us -- for the Power Corporation to achieve or
 2 that, in fact, there will be credits coming back to the Corporation. And, again, I
 3 guess without those details, we can't make an assessment.²⁰

4 Given the uncertainty surrounding new mining load and climate change regulation, deferral
 5 account treatment is not appropriate.²¹

6 **3. 2006/07 and 2007/08 GRA Forecasts**

7 **(a) Sales and Load Forecast**

8 NTPC's load forecast in this GRA was the subject of considerable review and detailed support
 9 was provided for the approaches employed.²² This attention arose despite the fact that NTPC's
 10 approach in this GRA reflects the exact same methodology as used and approved as part of the
 11 2001/03 Negotiated Settlement.²³

12 The load forecasts prepared by NTPC reflect its best estimate of how loads will unfold. The
 13 most substantial support for NTPC's approach to load forecasting is the success NTPC has with
 14 respect to the accuracy of the forecasts. Notably, the 2001/03 GRA forecasts for Corporate-wide
 15 sales varied less than 1% from forecast and the results by retail customer class (residential,
 16 commercial and streetlighting) are within approximately 2% in all but one case.²⁴ Further, the
 17 preliminary actual loads for 2006/07 for the thermal communities indicate sales overall in these
 18 communities are within 1.2% of forecast levels.²⁵

19 NTPC acknowledged that below the aggregate Corporate-level, load forecasting at a community
 20 level is very challenging:

21 MR. AZAD MERANI: Thank you, sir. Moving on to the sales forecast issue.
 22 This is a general question.

23 Do you -- do you consider forecasting sales for the thermal generating
 24 communities poses the company a fair level of challenge?

25 And I'll try and shorten this discussion.

26 If you turn to BR-4, I believe it's BR-4, part A. You say on page 2 of 23:

27 "due to lack of -- due to lack of economies of scale, in a thermal community very
 28 small changes can have a material impact on the year-over-year results."

²⁰ Tr. I, p. 28, ln. 20 to p. 29, ln. 2.

²¹ Tr. I, p. 63, lns. 2-12; Tr. I,

²² Ex. 2, Chapter 2; Ex. 7, BR.NTPC-4.

²³ Ex. 2, p. 2-14, lns. 10-11; PUB Decision 1-2002 at s. 4(f) and (e), pp. 16-20.

²⁴ Ex. 7, BR.NTPC-4(a). Streetlights in 2002/03 were below forecast by 4.2% due to more efficient lights being installed at a faster pace than originally anticipated.

²⁵ Ex. 32.

1 I took that to mean that forecasting sales for the thermal communities poses a fair
2 challenge in relation to forecasting sales, for example, for the hydro communities.

3 MR. PATRICK BOWMAN: Absolutely, Mr. Merani. Forecasting for the thermal
4 communities is a -- is a massive challenge. Even forecasting for the hydro
5 communities, in many cases, is -- is a very difficult exercise.

6 You can see by the undertaking I filed earlier today that in something like Fort
7 Smith, trying to apply sophisticated methodologies like other utilities use,
8 sometimes just -- just won't work on a community as small as Fort Smith. And, of
9 course, Fort Smith, as most people know, is one of the larger communities the
10 Corporation forecasts for.

11 So, when you get down to some of these very small communities, it is a -- it is a
12 massive challenge to try to get a forecast that -- that will -- will -- will hold up and
13 -- and at the end of the day, it's -- it's generally not even possible to meet the kind
14 of -- of accuracy test that a large utility would use.²⁶

15 Notwithstanding this challenge, the Corporation's response to Undertaking No. 14 indicates that
16 of the 22 communities listed, only seven communities fall outside a threshold of approximately
17 3-4% variance from forecast.²⁷ The most notable variances among these communities were
18 driven by unforeseeable factors or factors that are very difficult to forecast, such as use of
19 construction power.²⁸ In other cases, such as Jean Marie River, the variance is 7.9%, but totals
20 only 19 MW.h, which is approximately equal to two houses using 700 kW.h each month (a
21 typical residential load for the thermal communities).²⁹

22 Ms. Goucher and Mr. Bowman subsequently discussed the Corporation's wholesale customers
23 forecasting methodology with Mr. Retnanandan. They noted that the wholesale forecast involves
24 consultations with NUL, information from the GNWT's capital plan and the NWT Construction
25 Association, and general information about mining and oil & gas activity, as well as recent
26 weather conditions. The Corporation takes NUL's forecast and adjusts it using a "top down"
27 approach based on the foregoing.³⁰

28 No evidence was submitted by any intervenor challenging NTPC's sales and load forecast.
29 Consequently, NTPC submits that the sales forecast provided in Chapter 2 and Appendix A of
30 the Application is reasonable and should be approved by the Board.

²⁶ Tr. II, p. 58, ln. 9 to p.59, ln. 19.

²⁷ Ex. 32.

²⁸ Tr. III, p. 88, ln. 9 to p. 89, ln. 13.

²⁹ Ex. 32.

³⁰ Tr. II, p. 130, ln. 6 to p. 134, ln. 17.

1 **(b) Station Service and Losses**

2 NTPC's approach to forecasting station service and losses is set out at pages 2-10 to 2-11 and 2-
3 17 of the Application.³¹ Further detail is provided in BR.NTPC-5.³²

4 Except for Taltson, the Corporation's line losses as a percentage of sales have declined from
5 6.01% to 4.95% since the last GRA. In the case of Taltson, percentage losses are high reflecting
6 the unavoidable characteristics of substantial and lightly loaded transmission, and in any event
7 do not drive costs in the Revenue Requirement as they are served by surplus hydro.³³

8 BR.NTPC-5 requested NTPC to provide an explanation as to communities where losses were
9 higher than 7%. The 10 communities listed reflect basically the same communities that have had
10 losses in the higher end of the range going back to the Board's Decision 9-93 and that
11 investigations have been done over a long period of time on these communities. While generic
12 approaches that can be employed to reduce line losses (such as reconductoring or voltage
13 conversion) are expensive and not practical in these cases, "[n]o other cost effective steps or
14 investigations have been identified at this time to reduce losses".³⁴ Consequently, NTPC submits
15 that the line losses indicated in the GRA are a reasonable, valid and justified cost of operating its
16 systems, and as such should be approved the Board as part of calculating the NTPC's Revenue
17 Requirement.

18 Ms. Goucher noted in her opening comments an error in the calculation of the line losses for
19 Norman Wells.³⁵ The Corporation proposes that this error be corrected (line losses reduced and
20 consequently Revenue Requirement reduced) in its final GRA refiling.

21 On the matter of station service, station service loads have decreased by over 1 GW.h per year
22 since the last GRA. On a percentage basis that translates to a drop from 3.77% of corporate-
23 wide sales to 3.53%.³⁶ This drop is despite the fact that station service loads at Jackfish have
24 increased due to installation of an electric heating system in the plant required as the result of
25 less waste heat due the reduced diesel operations. Jackfish station service is served by surplus
26 hydro.

27 The Corporation has implemented a number of initiatives to reduce station service, such as
28 installing residual heat systems, jacket water heating to replace electric block heating, variable
29 frequency drives on exhaust and radiator fans.³⁷ NTPC's witnesses addressed the fact that there
30 is limited potential to further improve on reducing station service loads.

31 MR. AZAD MERANI: And sir, what I'm trying to get at, at the end of the day if
32 the Board were to direct you to look at station service and -- and -- and ask you,

31 Ex. 2.

32 Ex. 7.

33 Ex. 2, p. 2-10.

34 Ex. 7, BR.NTPC-5(a).

35 Tr. I, p. 34-35.

36 Ex. 2, p. 2-10.

37 Tr. II, p. 47, lns. 7-20.

1 for example, to ratchet down the 5 percent to, let's say, 3 percent, I'm just pulling
2 a number from the air here, you know, how would you -- how would you be
3 incented to bring that station service down?

4 What would you have to do to -- to bring it down to a level that is -- not
5 suggesting Colville Lake, but certainly lower than 5 percent where most of the
6 communities seem to be lying south of 5 percent in any event?

7 But if you we're asked by the Board to bring it down, what would you have to do?

8 (BRIEF PAUSE)

9 MR. STEPHEN KERR: I guess for the Power Corporation to try to achieve
10 something -- some target, arbitrary target, that would be imposed would probably
11 take a lot of money and investment, particularly, in some of the older plants to try
12 and go in and retrofit those facilities; that would mean fairly significant capital
13 dollars in some place for probably minimal return. So I'll -- for us to undertake
14 that, we could certainly attempt it, but at the end of the day I'm not sure it would
15 be in the best interest of our customers.

16 MR. PATRICK BOWMAN: Mr. -- Mr. Merani, I -- I might just add not -- not
17 being from here, I may have some of the same challenges as -- as you do
18 understanding these plants, but to put some numbers into context.

19 In -- in Jean Marie River the station service loss, as you note, are a fairly high
20 percentage, but, it actually works out to about 2,500 kilowatt hours a month which
21 is probably not much more than my house uses.

22 The total cost of serving that station service is about six thousand (\$6,000) dollars
23 a year in fuel. If -- if one were to be able to go in and find a way to cut that back
24 by -- by say, 25 percent, you'd be saving about fifteen hundred (\$1,500) dollars a
25 year.

26 It's really hard to start to think about how much you can invest in capital to save
27 fifteen hundred (\$1,500) dollars a year in Jean Marie River where projects are
28 quite expensive to -- to carry out.³⁸

29 No evidence was submitted by any intervenor challenging NTPC's station service or line loss
30 forecasts. Consequently, NTPC submits that the station service, line losses and overall load
31 forecast provided in Chapter 2 and Appendix A of the Application is reasonable and should be
32 approved by the Board.

33 **4. Revenue Requirement**

34 The Corporation's revenue requirement reflects the forecast cost of providing service in the
35 2006/07 and 2007/08 test years, as set out in Chapter 3 of the Application.³⁹ The Corporation's

³⁸ Tr. II, pp. 48-50.

³⁹ Ex. 2. Subject to certain minor revisions as described in the Corporation's May 16, 2007 Re-filing (Ex. 13).

1 revenue requirement is comprised of operating and maintenance expenses, fixed asset
 2 amortization, amortization of deferred costs, and return on rate base, including a fair return on
 3 equity. Specific components of the revenue requirement are discussed in further detail in the
 4 following sections.

5 **(a) Operating and Maintenance Expenses**

6 The Corporation's Operating and Maintenance Expenses are discussed at pages 3-6 through 3-12
 7 of the Application.⁴⁰ Operating and Maintenance Expenses comprise \$30.881 million of the
 8 2006/07 revenue requirement and \$32.341 million of the 2007/08 revenue requirement.⁴¹
 9 Components of the test year operating and maintenance expenses are described below. These
 10 costs are required to maintain reliable service 24 hours a day, seven days a week, 365 days a
 11 year.

12 **(i) Salaries and Wages**

13 The Corporation's salaries and wages expense is comprised of all salaries and wages, overtime,
 14 standby pay and call-back pay for full time and casual employees, at-risk compensation for 30
 15 management positions, as well as related benefits including employment insurance, Canada
 16 pension plan, health insurance, public service pension plan, northern living allowance and local
 17 differential payments. Salaries and wages are forecast at \$17.370 million for 2006/07 and
 18 \$18.552 million for 2007/08 and discussed in detail on pages 3-7 through 3-9 of the
 19 Application.⁴² In addition to general inflation, the key drivers in salaries and wages expenses
 20 since the 2002/03 test year include:

- 21 • additional positions required to meet the requirements of safety and environmental
 22 legislation;
- 23 • additional apprentice position to assist in the development and retention of trades-people in
 24 high demand position; and
- 25 • implementing the recommendations of the job evaluation program undertaken to comply
 26 with the GNWT "Equal Pay for Work of Equal Value" legislation.⁴³

27 Taking proactive measures and incurring the associated costs to address more stringent
 28 regulatory requirements and tight labour markets is both reasonable and prudent, since it avoids
 29 the likely higher costs of having to respond to an avoidable situation, such as a breach of
 30 regulatory requirements, extended trades vacancies or employment standards complaint.

31 With respect to the overall level of increases in salaries and wages expense from 2002/03, Mr.
 32 Bowman noted that the annual average increase was approximately 4.43 per cent for union
 33 employees and 4.23 per cent for excluded positions.⁴⁴ Mr. Bowman also noted:

⁴⁰ Ex. 2.

⁴¹ Ex. 13, Schedule 3.1.1 (revised May 16, 2007).

⁴² Ex. 2; Ex. 13, Schedule 3.1 (revised May 16, 2007).

⁴³ Ex. 2, p. 3-7 ln. 15 to p. 3-8, ln. 21.

1 But I think – I think to recognize the value of this – this type of exhibit [HC’s aid
2 to cross, Ex. 22], or these type of numbers, is that over the long term, as I say, it –
3 it really is something that the Corporation was feeling quite comfortable with that
4 – that about 4.2 to 4.4 percent a year salary growth in the base salaries was
5 something that – that seemed to be a meaningful number to them.⁴⁵

6 With respect to salaries and wages expense for the Snare Yellowknife system, Ms. Goucher
7 stated:

8 [s]o although you are seeing some reductions in salary costs from the plant
9 operators that are no longer at Jackfish, you are seeing the additional costs of
10 the staff at Bluefish and, in addition, you’re seeing the costs for the entire
11 system over the past four (4) years related to collective agreement increases
12 and also the implementation of the new job evaluation [Hay Plan] system.⁴⁶

13 During the course of hearing, counsel for the Hydro Communities pursued a line of questioning in
14 an attempt to understand whether reductions in generation requirements at the Jackfish diesel
15 facility should result in decreased salaries and wage expense “at Jackfish”. In response to
16 Undertaking No. 2, which requested the positions represented by the salary costs in HC.NTPC-
17 13(g) at Jackfish, Ms. Goucher said:

18 ...the number of positions across this Snare system has been constant over this
19 period. In 2004/05 it was forty-one (41); 2005/’06, thirty-nine (39); 2006/’07,
20 thirty-nine (39); and 2007/’08, forty-one (41).

21 Plant operator positions at Jackfish have been reduced by five (5). However,
22 positions have been added for Bluefish and the Apprentice program. Over this
23 period the administration positions for the Snare/Yellowknife system, which
24 were included in the Jackfish numbers on that table have been constant at five
25 (5) throughout the four (4) years.

26 Operational positions, however, are utilized across the system. Personnel are
27 deployed where they are needed according to the system requirements and
28 therefore their salaries are allocated across the system either to Jackfish, Snare
29 or Bluefish, depending on where the operation need is.

30 And this is done to take advantage of economies of scale, which is our biggest
31 challenge, and as a result, the salary dollars that you see there don’t reflect any
32 one (1) or two (2) or forty-one (41) positions; they’re the time spent by the
33 entire operational staff, and therefore we were not able to specifically say this
34 position is dedicated to Snare, this position is dedicated to Bluefish and this
35 position is dedicated to Jackfish.⁴⁷

⁴⁴ Tr. I, p. 134, lns. 12-20.

⁴⁵ Tr. I, p. 135, lns. 10-17.

⁴⁶ Tr. I, p. 71, lns. 18-25.

⁴⁷ Tr. III, p. 80, ln. 3 to p. 81, ln. 5.

1 With respect to at-risk compensation, the Corporation's response to BR.NTPC-10(b) and (c) set
2 out the following specific information related to this program.⁴⁸

- 3 • Senior management salaries and at-risk (performance based component) are set by the Board
4 of Director's Governance and Compensation Committee (the "Committee") and approved by
5 the Board of Directors with the assistance of outside consultants who conduct a detailed
6 study every three years with informal updates between formal studies.
- 7 • The Committee adopted the process of setting senior management salaries based on being
8 within 10% (plus or minus) of the 50th percentile. The results of the last detailed survey in
9 2004 found that the President & CEO's total compensation (salary and at-risk) were within
10 the target range. The survey also found that while the salaries for the Directors' positions
11 were within the target range and the at-risk component of Director's compensation was, in
12 general, below the target range.
- 13 • Prior to April 1, 2007, the at-risk compensation plan covered all management and excluded
14 positions – approximately 40 positions. The avoided cost of paying overtime for a year
15 instead of the at-risk compensation for all positions excluding officers of the Corporation was
16 estimated at \$425,000.⁴⁹ After April 1, 2007 excluded positions were no longer are eligible
17 for at-risk compensation (they now receive overtime instead) and the number of positions
18 included in the plan will be approximately 30.
- 19 • For each position's eligible pool, 50% of the potential amount is based on net income targets,
20 25% is based on the achievement of individual objectives and 25% is based on the
21 achievement of operational targets.

22 During the hearing Ms. Goucher responded to questions from counsel for the Hydro
23 Communities on what would happen if costs budgeted for the program were not incurred. Ms
24 Goucher replied that "[t]he amounts paid out have typically always been higher than what's
25 included in rates, so I have no knowledge of what would have occurred had the amounts not have
26 been paid out other than it would have been a – been an expense not incurred."⁵⁰

27 Given the evidence on the record, the Corporation submits that its forecast salary and wage
28 expenses in the test years are reasonable and necessary, and should be approved.

29 (ii) Non-Production Fuel

30 Non-production fuel, which includes the cost of fuel for buildings and vehicles, is forecast at
31 \$0.730 million and \$0.745 million in 2006/7 and 2007/08, respectively. The 2006/07 GRA cost
32 increases since the 2002/03 test year generally reflects the overall pressure of higher fuel costs.⁵¹
33 The Corporation noted that non-production fuel expense was unusually low in 2005/06 as a
34 major fuel delivery was made to Snare in March 2005 that was required primarily for use during

⁴⁸ Ex. 19.

⁴⁹ Ex. 5, NY.NTPC-1, p. 11.

⁵⁰ Tr. I, p. 167, Ins. 16-20.

⁵¹ Ex. 2, p. 3-9, Ins. 7-9; Ex. 13, Schedule 3.1 (revised May 16, 2007).

1 the 2005/06 year but was expensed in the 2004/05 fiscal year.⁵² The Corporation submits that its
 2 forecast expense related to Non-production fuel is prudent and reasonable, and should be
 3 approved by the Board as applied for.

4 **(iii) Supplies and Services**

5 Supplies and services represent the cost of maintaining the Corporation's plants and equipment
 6 and include such costs as supplies, freight, contractors, professional development and
 7 administration. Forecast supplies and services costs are \$10.748 million for 2006/07 and
 8 \$10.948 million for 2007/08.⁵³ Key factors driving increases in supplies and services costs in the
 9 test years are discussed on pages 3-10 through 3-11 of the Application and include:

- 10 • insurance costs and appropriations to the Reserve for Injuries and Damages ("RFID") as a
 11 result of changes to the RFID policy directed by the Board (see section 4(e)(i) below); and
 12 • brushing costs to maintain the reliability of distribution and transmission systems.

13 The RFID drives higher supplies and services expenses in two ways: as an increased
 14 appropriation to pay down the existing balance in the RFID and also to account for events that
 15 are no longer charged to the RFID as a result of the new RFID policy. Primarily this will include
 16 events in the \$5,000 to \$100,000 range. Mr. Bowman explained the changes as follows:

17 ...there are increases needed for both the appropriation to the reserve, as I went
 18 through earlier, which used to be four hundred and eighty-five thousand (485,000)
 19 a year and is now six hundred and seventy thousand (670,000) a year for the
 20 reasons I talked about when we were at TGC-55 interrogatory.

21 That six-seventy (670) a year will be charged through this category and so that
 22 changes approximately two hundred thousand dollar (\$200,000) increase. That
 23 six seventy (670) even though it's larger than the previous appropriation, it covers
 24 a narrower scope of events and – and it's for the reasons I set out earlier, that
 25 there's a balance that needs to be paid down.

26 And as a result, those addition events, the five thousand (5,000) to one hundred
 27 thousand (100,000) are built into two (2) different parts of this table. Primarily
 28 they were built into the mat – materials row where there – there are three hundred
 29 thousand dollars (\$300,000).⁵⁴

30 With respect to brushing expense, Mr. Courtoreille discussed with counsel for the Hydro
 31 Communities the response to BR.NTPC-12(b) and noted that:

32 [h]istorically the Corporation would conduct its brushing requirements on an as-
 33 and when-needed basis. Recently, however, the Corporation undertook an
 34 internal evaluation of its brushing requirements and the forecast numbers that you

⁵² Ex. 7, BR.NTPC-8.

⁵³ Ex. 13, Schedule 3.1 (revised May 16, 2007) Schedule 3.1.

⁵⁴ Tr. II, p. 141, ln. 24 to p. 142 ln. 19.

1 see proposed for the test years in this table would represent what we're proposing
2 as our minimum brushing requirements on an annual basis.⁵⁵

3 The Corporation submits that its test year forecasts for supplies and services expenses are
4 prudent and reasonable, and should be approved by the Board as applied for.

5 **(iv) Travel and Accommodation**

6 Travel and accommodation expense includes all the travel, accommodation and meal costs
7 associated with staff travel related to both operational and professional development
8 requirements. Travel and accommodation costs are forecast at \$2.135 million for 2006/07 and
9 \$2.199 million for 2007/08.⁵⁶ In addition to general inflation, key drivers for this category in the
10 test years include:

- 11 • Training required due to increased regulatory requirements. This was discussed by Ms.
12 Goucher, who stated that:

13 [t]he majority of the training that is scheduled for each of the two (2) test years
14 is in response to increased regulatory requirements. Part of that is associated
15 with the implementation of the Corporation's Environmental Management
16 System. So a lot of this travel relates to bringing in numbers of plant operators
17 into central regions so that they can have training on the environmental systems
18 and any other type of safety training that they require in order to meet the
19 legislation and regulation standards. *So it's mandatory training under*
20 *regulation that is driving most of that cost.*⁵⁷ [emphasis added]

- 21 • Travel related to expenses that would previously have been charged to the RFID now are
22 included as part of the Corporation's operating and maintenance budgets because of the
23 revised RFID policy. Ms. Goucher explained this change during the hearing, saying:

24 ...that four hundred thousand dollars (\$400,000) a year average is all those
25 charges between five thousand (5,000) and a hundred thousand (100,000) which
26 will now go to the Corporation's O&M budgets. In order to therefore reflect
27 that there will be these costs, the Corporation has – has added to what it would
28 otherwise budget, based on past experience, four hundred thousand dollars
29 (\$400,000) in its O&M budgets; three hundred thousand (300,000) of which
30 was included in the supplies and services category, and one hundred thousand
31 (100,000) of it was included in the travel and accommodation category.⁵⁸

32 It is notable, however, that the GRA forecast significantly decreases medical travel and
33 accommodation expenses from \$163,000 in 2005/06 to \$99, 000 and \$102,000 in 2006/07

⁵⁵ Tr. I, p. 155, lns. 6-14.

⁵⁶ Ex. 2, p. 3-11, lns. 21-23; Ex. 13, Schedule 3.1 (revised May 16, 2007).

⁵⁷ Tr. I, p. 158, ln. 23 to p. 159, ln. 10.

⁵⁸ Tr. II, p. 103, ln. 21 to p. 104, ln. 8.

1 and 2007/08, respectively, notwithstanding that those costs are difficult to forecast and
2 unavoidable.⁵⁹

3 The Corporation submits that its test year forecasts for travel and accommodation expenses are
4 prudent and reasonable and should be approved by the Board as applied for.

5 **(b) Production Fuel**

6 Production fuel expense includes both fuel and purchased power expenses. Production fuel
7 expense forecasts for the test years are described on pages 3-12 through 3-13 of the
8 Application.⁶⁰ Production fuel expense forecasts included in revenue requirement for the test
9 years are \$16.639 million for 2006/07 and \$17.423 million in 2007/08.⁶¹

10 Fuel volume requirements for the test years are forecast based on the last three years of actual
11 efficiency, weighted “3” for the highest of the past three years, “2” for the middle efficiency year
12 and “1” for the lowest efficiency of the three years. This is the same as the method agreed to in
13 the 2001/03 Negotiated Settlement.⁶² The Corporation also provided evidence during the
14 hearing noting that in some newer diesel engines, fuel efficiency is actually lower than previous
15 technologies in order to maximize emissions reduction objectives.⁶³ The Corporation submits
16 that this method is reasonable and produces results that are favourable to customers since it
17 ascribes the heaviest weighting to the highest efficiency.

18 The Corporation deviated from this method in two instances. In Fort McPherson, where a fire
19 resulted in an entirely new plant being constructed, the fuel efficiency forecast reflects the actual
20 operating experience with the new plant. For the Jackfish diesel plant, the forecast efficiency has
21 been revised to reflect the much lower usage of the diesel plant since the decline of the mine
22 loads.⁶⁴

23 The Corporation submits that its fuel efficiency forecasts for the test years are reasonable and
24 should be approved.

25 With respect to the acquisition of fuel, the Corporation has entered into a Fuel Services
26 Agreement with the GNWT’s Petroleum Products Division (“PPD”). Under that agreement
27 diesel fuel will be supplied to eighteen of the Corporation’s serviceable communities at a price
28 set by the PPD. The five excluded communities will continue to be serviced by the
29 Corporation.⁶⁵

30 Mr. Kerr described the reasons for entering into the PPD agreement.

⁵⁹ Ex. 7, Table BR.NTPC-8.

⁶⁰ Ex. 2.

⁶¹ Ex. 13, Schedule 3.1 (revised May 16, 2007). \$17.150 million less \$0.511 million that would flow through the fuel stabilization funds in 2006/07 and \$17.848 million less \$0.425 million that would flow through the fuel stabilization funds in 2007/08.

⁶² Ex. 2, p. 2-18, ln. 9-10.

⁶³ Ex. 12, NTPC Rebuttal Evidence, p. 15, lns. 26-28.

⁶⁴ Ex. 2, p. 2-18, ln. 10-13.

⁶⁵ Ex. 2, pp. 6-4, lns. 14-18.

1 So the Corporation felt that Petroleum [Products] Division has a mandate to
2 supply this little [post-Division fuel] supply services to a number of the
3 communities in which we operate. And we decided that it would be a prudent
4 business decision on our part to amalgamate our fuel supply services with those –
5 with that department.

6 We looked at it from a number of aspects; one (1) of them being the reduction in
7 our inventory carrying costs and weighed that against some of the other operating
8 costs that we have and we feel that the arrangement is essentially cost neutral in
9 the – in the short term.

10 In a longer term, the benefits will be the, I guess, common tank farms and the
11 reduction in Power Corporation's time and involvement with fuel and to transfer
12 some of the responsibilities with respect to training and environmental
13 responsibilities for those activities.⁶⁶

14 Mr. Bowman had the following exchange with Mr. Merani about the analysis
15 undertaken by the Corporation to determine that the PPD contract was essentially
16 revenue neutral.

17 ...[I]f I look to one (1) given test year, 2007/'08 is probably the easiest one (1) to
18 analyze. The costs related to the PPD contract relate to the costs NTPC pays to
19 PPD over and above the product price in order to deal with all of the fuel supply,
20 the -- the markup, for lack of a better term, in the contract and that is set at eight
21 cents (.08) a litre and you'll find that in the PPD contract which is attached to one
22 (1) of the interrogatories. On -- on the 11.3 million litres forecast to be used in
23 '07/'08 that's about nine hundred thousand dollars (\$900,000).

24 MR. AZAD MERANI: So --

25 MR. PATRICK BOWMAN: The bene -- about nine hundred thousand (900,000).

26 MR. AZAD MERANI: That's the markup as you --

27 MR. PATRICK BOWMAN: That -- that's the markup, for lack of a better term.
28 Now, PPD did previously supply NTPC with fuel in a number of communities
29 and in those communities there was previously a markup which was somewhat
30 higher and as a result of -- of the new markup we no longer pay the old markup
31 and the old markup would have worked out to in the test years about --
32 somewhere around five hundred thousand dollars (\$500,000). So the net increase
33 in amounts paid to PPD in -- under this contract compared to what would have
34 been is about -- about four hundred thousand dollars (\$400,000) in rough
35 numbers. Now, the key offset to that that Mr. Kerr referred to is that NTPC
36 effectively no longer has any fuel -- material fuel inventory and that can be seen
37 in the rate-based tables in Chapter 5 and if you -- in -- in -- within the rates of
38 these tables you find that historically over the last number of years -- I don't -- I

⁶⁶ Tr. I, p. 279, ln. 18 to p. 280, ln. 10.

1 don't know if it's -- if it helps you to turn to them or -- or to -- to be able to look
2 this up later but it's Schedule 5.5.

3 And for example in 2004/'05 the Corporation's fuel inventory was on the order of
4 \$5.2 million. This is Schedule 5.5 in Chapter 5.

5 MR. AZAD MERANI: Yes, sir.

6 MR. PATRICK BOWMAN: If you look across that inventory line, you'll see that
7 by the time we get to '07/'08 then all these communities have been converted to
8 PPD. The amount of inventory left of NTPC's actual fuel is a hundred and forty-
9 five thousand (145,000) so it's down by some \$5.1 million and that goes straight
10 to the rate base of the Corporation. Now, in rough numbers it's -- the -- the
11 overall carrying cost of rate base is a little over 10 percent so by the time you take
12 five (5) -- a little over \$5 million at a little over 10 percent you're talking about
13 something -- something on the order of -- of five hundred thousand (500,000) to --
14 to round down in terms of the -- the savings to return on rate base related to the
15 PPD contract. So that's -- that's the order of magnitude we're talking about in the
16 numbers. They -- they work out within -- within about a hundred thousand
17 dollars (\$100,000) of costs neutral.

18 I think if -- if I recall correctly the hundred (100) -- the hundred thousand
19 (100,000) is to the good to ratepayers but I think the key thing that -- that's noted
20 in the IR that you were referencing is that -- is that the Corporation's test for the
21 contract was not to find a way to reduce its costs in the tests years over the short
22 term; it was to find a way to free up its staff from having to deal with this major,
23 you know, major exercise for not a major amount of fuel anymore.⁶⁷

24 As Mr. Kerr noted, the Corporation's fuel requirements have decreased 87% from approximately
25 100 million litres to approximately 13 million litre since Division.⁶⁸

26 With respect to appropriate fuel price benchmarks, the only relevant benchmark identified and
27 routinely used by the Corporation is the Edmonton rack price, upon which most diesel fuel
28 pricing for Western Canada is based. Mr. Kerr further explained that "[t]he Corporation's not
29 used any other benchmarks other than the Edmonton rack. I would say that 90 percent of all the
30 fuel in the Power Corporation is used in the western [Arctic] area comes from Edmonton
31 refineries."⁶⁹ In contrast, local NWT prices for other fuels (such as heating fuel) are not a good
32 benchmark as heating fuel pricing does not include fuel tax and is therefore considerably lower
33 than the prices for diesel fuel.⁷⁰ Mr. Bowman perhaps summed up best in saying "[h]ow do you
34 know you're getting a good deal compared to Edmonton rack -- well, because of the PPD

⁶⁷ Tr. I, p. 281, ln. 15 to p. 284, ln. 11.

⁶⁸ Tr. I, p. 279, lns. 2-13.

⁶⁹ Tr. I, p. 285, ln. 24 to p. 286, ln. 3.

⁷⁰ Ex. 2, pp. 6-5, lns. 5-9.

1 contract, the Corporation's getting the same deal as everybody else in the Northwest Territories
2 to begin with because it's getting the same landed price."⁷¹

3 With respect to the Inuvik gas contract, Mr. Kerr explained that "...the price of natural gas in
4 Inuvik is actually tied to the change in the Edmonton rack price, but only 50 percent of that
5 change".⁷² Mr. Bowman added that the intent of the contract was to reflect savings to fuel
6 expense for using natural gas instead of diesel. He stated that "[w]e're setting up a contract that
7 saves money relative to diesel."⁷³ Finally, when asked by Mr. Merani if the Corporation would
8 consider reopening the Inuvik Gas contract and considering some other pricing index, Ms.
9 Goucher cautioned:

10 [t]hat would be something that we would consider at the time the contract is up
11 for renewal. And I believe it's a fifteen-year (15) contract that we've entered into.

12 And as Mr. Bowman indicated, the Corporation is a signatory to that contract, so,
13 changing the rules or the underlying principles of the contract at this point in time
14 is not an option.⁷⁴

15 Based on the evidence on the record in this proceeding, the Corporation submits that its test year
16 forecasts for fuel expense are prudent and reasonable, and should be approved by the Board as
17 applied for.

18 **(c) Fixed Asset Amortization**

19 The Corporation's fixed asset amortization expense forecasts for the test-years are described on
20 pages 3-14 through 3-15 of the application. Fixed asset amortization expenses included in the
21 test year revenue requirements are \$9.568 million in 2006/07 and \$10.115 million in 2007/08.⁷⁵

22 In the application the Corporation noted that a key driver in increased amortization expense in
23 the test years is the end of certain amortization credits that were in place in 2002/03 – primarily
24 the "true-up" arising from the 2001/03 Phase I Negotiated Settlement.⁷⁶ In preparing its fixed-
25 asset amortization expense forecasts for the 2006/07 and 2007/08 the Corporation used the same
26 amortization rates agreed to in the 2001/03 Phase I Negotiated Settlement.

27 During the interrogatory process, the Board asked whether NTPC had prepared a depreciation
28 technical update and why the Corporation had not re-calculated a new amortization true-up
29 amount for the test-period. In its response to BR.NTPC-14 (b) and (c) the Corporation stated:

30 NTPC has not completed a depreciation technical update with revised
31 amortization rates based on newer historical information. NTPC has continued to

⁷¹ Tr. I, p. 290, lns. 7-11.

⁷² Tr. II, p. 29 lns. 18-20.

⁷³ Tr. II, p. 31, ln. 25 to p. 32, ln. 1.

⁷⁴ Tr. II, p. 33, lns 7-14.

⁷⁵ Ex. 13, Schedule 3.1 (revised May 16, 2007).

⁷⁶ Ex. 2, Application, pp. 3-14, lns. 5-7. See also Ex. 3, SM-2 – YK/HR/FS-4 Amort. Credits table.

1 use the amortization rates approved in the negotiated settlement. The
2 amortization true up from the negotiated settlement has ended.

3 NTPC began but did not complete a depreciation study. NTPC did full
4 depreciation studies for the last two GRA's which provided detailed reviews of
5 asset lives and site restoration costs. Utilities do not normally do full
6 depreciations studies for every GRA.

7 The current GRA requires a large increase to deal with fuel price increases, loss
8 of credits, investment, regulation and inflation. The preliminary work on the
9 depreciation study was indicating the need for additional increases due to
10 depreciation and NTPC did not want to apply for any potential increases at the
11 same time as the other increases and not without a more thorough review of the
12 study results and more information on how Asset Retirement Obligations (ARO)
13 recommendations of the Canadian Institute of Chartered Accountants (CICA) will
14 impact depreciation rates, true ups, equity and the Revenue Requirement.

15 The various methods of dealing with the new ARO's have the potential to have a
16 material impact on NTPC's GRA and depreciation rates depending on whether
17 the recommendations of the CICA are followed or ignored for rate making
18 purposes or whether the Board approves NTPC's proposal in the GRA or whether
19 the Board approves another approach to for dealing with ARO's.

20 Once the question of how ARO's will be handled NTPC will complete a new
21 depreciation study reflecting newer historical information, updated site restoration
22 information and the approved ARO treatment.⁷⁷

23 NTPC submits that its forecasts for fixed asset amortization expense in the 2006/07 and 2007/08
24 test years are reasonable and should be approved.

25 (d) Amortization of Deferred Charges

26 Amortization of deferred charges relate to deferred costs that have enduring value and are
27 therefore amortized over a set period rather than expensed in the year they arise (such as the job
28 evaluation study) and also annual appropriations to deferral accounts that are approved by the
29 Board. Amortization of deferred charges are discussed on pages 3-15 through 3-17 of the
30 Application. The Corporation's forecast for deferred charges amortization is \$2.502 million for
31 each of the 2006/07 and 2007/08 test years.⁷⁸

32 (i) Overhaul Deferral Account

33 The Overhaul Deferral Account was established as part of the 2001/03 GRA Phase I Negotiated
34 Settlement and was intended to "normalize" the cost of overhauls on an annual basis by
35 appropriating a standard annual amount per year to a deferral account representing the long-term
36 average cost of overhauls by community, and charging all actual overhaul spending to this
37 account. The deferral account has generally tracked well since it was established, with the

⁷⁷ Ex. 7, BR.NTPC-14(b) & (c).

⁷⁸ Ex. 13, Schedule 3.1 (revised May 16, 2007).

1 exception of three communities where increased appropriations are required. The Corporation is
2 requesting increases to the annual appropriation in the amount of \$0.120 million with respect to
3 those communities and to include a normalized overhaul provision related to the Bluefish
4 generating station.⁷⁹

5 During the hearing, counsel for the Hydro Communities questioned whether the overhaul
6 deferral account was intended to capture only diesel overhaul expenses or also hydro overhauls.
7 Mr. Marriott and Mr. Bowman had the following exchange on the topic:

8 MR. TOM MARRIOTT: So is there anywhere in the negotiated settlement that
9 refers to hydro overhauls?

10 MR. PATRICK BOWMAN: Mr. Chairman, no, not specifically. The -- after the
11 settlement was reached, the Corporation went back to determine how to apply this
12 -- these amounts to its accounts. In the section on overhauls, the wording that
13 was agreed to, over quite a hectic week I might add, specifically states:

14 “The Corporation will establish deferral accounts for overhauls for each
15 community. An estimate of the average annual cost for overhauls will be
16 included in the rates as an accrual to -- to the accounts and actual costs incurred
17 for overhauls will be charged to the account in the year incurred.”

18 That section then goes on to say:

19 “The estimate of average annual costs for overhauls of the Corporation’s diesel
20 units is shown in Schedule B. Overhauls are as described in Schedule B.”

21 The interpretation taken by the Corporation of this section was that the intent of
22 the parties -- and -- and it wasn’t -- this wasn’t the Corporation’s proposal, but
23 that the intent of the parties was that overhauls would be something that would be
24 normalized.

25 For those who are familiar with them you’d know that overhauls happen on a
26 periodic basic, not in any given year. And so when you set rates on a test year
27 basis if you get caught with an overhaul in a test year your rates are quite high; it
28 doesn’t mean it’s going to occur the next year and your rates might not be correct
29 for that or if you set rates on an -- without an overhaul, the next year you have an
30 overhaul, you end up with this -- I get teased for the term but -- with this “lumpy”
31 effect in your -- in your rate setting.

32 So in terms of -- of that, the Corporation went back, added up the amounts for the
33 diesel overhauls per Schedule B which works out to about \$1 million and also
34 went through its GRA and determined that there was approximately four hundred
35 thousand dollars (\$400,000), as I recall it, related to hydro overhauls for Snare
36 and for Taltson and as a result set up an annual provision to this account at \$1.5
37 million.

⁷⁹ These were described on pages 6-56 through 6-59 of the Application (Ex. 2).

1 So the amount -- the provision to the account is more than is included in Schedule
2 B and --

3 MR. TOM MARRIOTT: And there is --

4 MR. PATRICK BOWMAN: Sorry, and -- and I -- I'm just -- I'm -- I'm noted that -
5 - reminded that it also includes the -- the gas units in -- in Inuvik. But all -- all
6 costs in the rate application related to overhauls were set aside to flow through
7 this account.⁸⁰

8 The process and inherent reasonableness of overhaul expenses was subsequently discussed by
9 Mr. Retnanandan, Ms. Goucher and Mr. Bowman.

10 ...[G]iven that this [is] a deferral account, first of all, what incentive does the
11 company have -- or the Corporation have in order -- in -- in terms of improving
12 the efficiencies in -- in regard to overhaul expenditures? So that's one (1)
13 question and there -- well, maybe I'll let you answer that.

14 MS. JUDITH GOUCHER: Since the establishment of the overhaul deferral
15 account, the Corporation has not changed in any way how it reviews and
16 scrutinizes the overhaul budgets that are put forward by the operational regions.

17 The information that's put forward is based on their estimates of the actual
18 expenses that must be incurred during the year and it goes through the same
19 rigorous process as every other cost that is put forward in our budget exercise.

20 It goes through, as I mentioned earlier, the three (3) iterations of review and
21 everything must be substantiated. It gets approved on that basis and then those
22 costs are removed from the budget and the annual appropriation for the overhaul
23 reserve account are inputted.

24 So, the level of scrutiny has not changed because we have an overhaul deferral
25 account in place at this time.

26 MR. RAJ RETNANANDAN: All right. Are there -- are there any checks and
27 balances in terms of the cost per kilowatt hour for overhaul expenditures and --
28 and to what extent are these linked then to the -- to the operational targets and
29 other management rewards that -- that -- that we talked about on the BR-10?

30 MS. JUDITH GOUCHER: I'm not aware of any specific objective tied to
31 overhauls. Our overhauls are undertaken in accordance with the manufacturer's
32 recommendations in terms of hours run.

33 In terms of the cost to undertake the overhauls, I believe Mr. Bowman has a
34 comment to add.

⁸⁰ Tr. I, p. 204, ln. 20 to p. 206, ln. 25.

1 MR. PATRICK BOWMAN: I was just noting, Mr. Retnanandan, that when one
 2 (1) goes back to the negotiated settlement that was established from the last GRA,
 3 the Corporation had an overhaul budget in their rate application, which reflected
 4 the work they expected to do.

5 As a result of negotiated settlement, what was agreed with customers was to
 6 backout that forecast of what they expected to do and instead insert, as Mr.
 7 Merani and I went over yesterday, a -- a -- a forecast of what it should cost over
 8 time. And those forecasts -- the normal forecasts of what it should cost over time
 9 were developed at that negotiated settlement based on manufacturer's hours of
 10 ratings and any expected costs to an overhaul.

11 And I would just note that over all this balance has tracked very well to that
 12 overtime. It's a very modest adjustment we're dealing with today for -- for a
 13 limited number of communities.

14 Accordingly, NTPC submits that its requested appropriation to the Overhaul Deferral Account is
 15 prudent, reasonable and should be approved as applied for.

16 **(ii) Regulatory Deferral Account**

17 NTPC's Regulatory Deferral Account was established as part of the 2001/03 Phase I negotiated
 18 settlement to capture all third party costs and staff overtime, supplies, services and travel directly
 19 related to GRAs and related regulatory proceedings. The account was established with an initial
 20 annual appropriation of \$0.228 million.⁸¹

21 Additions to the Regulatory Deferral Account were set out in the Corporation's response to
 22 HC.NTPC-15 (d). In the Application, the Corporation noted that due to above forecast costs for
 23 the 2001/03 GRA and the costs incurred for the Review and Variance and Required Firm
 24 Capacity proceedings that were not anticipated at the time of the 2001/03 Negotiated Settlement,
 25 the balance in the regulatory deferral account is in excess of the amounts that can be recovered
 26 over the next five years at the current appropriation of \$0.228 million. Consequently, NTPC is
 27 seeking approval to increase the annual appropriation to \$0.600 million.⁸² The Corporation
 28 submits that the increased appropriation to the regulatory deferral account is reasonable and
 29 should be approved.

30 **(iii) Water Licensing Deferral Account**

31 In the Application, the Corporation noted that the 2002/03 revenue requirement included \$0.040
 32 million related to the deferred costs related to maintaining water licences on the Corporation's
 33 hydro facilities. Due to increasing uncertainty regarding the costs and terms of water licences in
 34 the NWT, NTPC is proposing to establish a new deferral account to capture the costs of all water
 35 licensing activities, including regulatory costs, compensation, environmental and dam safety
 36 studies, and related activities (excluding capital works) will be charged to the new deferral
 37 account.

⁸¹ Ex. 2, p. 6-52, lns. 7-8.

⁸² Ex. 2, p. 6-53, lns. 12-13.

1 The initial annual appropriation will be \$0.137 million beginning in the 2006/07 test year. That
 2 appropriation reflects the expected normal level of expenses over the next 15 years to secure and
 3 maintain NTPC's water licenses of \$2.185 million on a levelized basis over 16 years.⁸³ Should
 4 the costs vary from this level, either due to lower cost licence renewals and licence maintenance
 5 activities than forecast, or higher cost than forecast, the deferral account appropriation will be
 6 adjusted at a future GRA. In this manner, NTPC and customers are not prejudiced by actual
 7 costs for licences (which are generally not within NTPC's control) coming in higher or lower
 8 than forecast. This approach is consistent with the regulatory cost deferral for rate regulation
 9 expenses established in the 2001/03 Negotiated Settlement.

10 With respect to the difference between the proposed treatment of these costs in the test years and
 11 the way these costs were treated in the past, Mr. Bowman explained during the hearing:

12 So, in the past, if NTPC was to licence a plant, it would amortize the cost
 13 associated with that licence over the period of the licence. Because the cost that it
 14 incurred to licence the plant give value through that entire period of that licence.

15 What it's proposing to do now is to switch from that deferred cost accounting to
 16 this permanent deferral account -- account -- method of accounting, similar to the
 17 overhauls, in which there would be a set annual appropriation to the account and
 18 all -- all amounts required to be spent in respect of water licencing would be spent
 19 out of that deferral account.⁸⁴

20 The Corporation submits that the proposed deferral account treatment for water licensing costs is
 21 reasonable and should be approved.

22 (e) Other Deferral Accounts and Reserves

23 In addition to the deferral accounts discussed above, the Corporation also maintains certain other
 24 reserves or deferral accounts. These are described further below.

25 (i) Reserve for Injuries and Damages

26 The Corporation has maintained a RFID since it was first approved in PUB Decision 9-93. Costs
 27 related to uninsured or uninsurable losses and the deductible portion of insured claims are
 28 charged to the reserve. Pursuant to the Board's Decisions 9-93, 2-94 and 1-97, the Corporation
 29 included \$350,000 as an annual appropriation for the RFID from 1992/93 to 2000/01. Up to
 30 March 31, 2001 the fund applied to RFID claims from NWT and Nunavut operations of NTPC.⁸⁵
 31 In the 2001/03 GRA, the Corporation noted that the RFID was forecast to have a 2000/01 closing
 32 balance of negative \$0.924 million. An increased appropriation to the RFID in the 2001/03 GRA
 33 of \$0.485 million, made up of \$0.385 million of forecast annual spending and \$0.100 million to
 34 draw down the balance in the RFID, was approved as part of the 2001/03 Negotiated
 35 Settlement.⁸⁶ In the 2006/08 GRA, the Corporation is applying for approval to increase the

⁸³ Ex. 2, p. 3-16.

⁸⁴ Tr. I, p. 175, lns. 13-24.

⁸⁵ Ex. 7, TGC.NTPC-55 (c).

⁸⁶ PUB Decision 1-2002 at 9-10 and 20.

1 annual appropriation to the RFID to \$0.670 million.⁸⁷ This appropriation is included in the test
2 year revenue requirement as part of the Corporation's supplies and services expense.

3 Directive 2 from Decision 1-2002 required the Corporation to file a revised RFID policy that
4 "...restricts charges for uninsured and uninsurable losses to high impact, low probability, sudden
5 and accidental events...".⁸⁸ During the hearing counsel for the Hydro Communities asked if the
6 provisions of the proposed policy were consistent with the previous policy or if there were
7 differences. Ms. Goucher indicated that the policy was always intended to parallel the
8 Corporation's insurance coverage.

9 The reading of the previous -- or the wording rather of the previous policy was
10 always meant to dovetail with the insurance coverage that the Corporation had.

11 And so those types of clauses were meant to be implied within that policy but
12 they weren't specifically worded as they are now. So certainly the -- the policy
13 and the reserve was treated as if those premises were in place. But this wording is
14 much clearer and is extracted directly from our insurance coverage for clarity⁸⁹.

15 With respect to how charges to the RFID are reviewed, Ms. Goucher stated that:

16 ...on an annual basis we review the charges to the fund with the people who have
17 the knowledge of the events and we review with them the terminology of the
18 policy so that they have a good understanding of what events qualify under these
19 funds, in particular, the reserve for injuries and damages.⁹⁰

20 With respect to how the test year forecasts for the appropriation to the RFID were determined,
21 Mr. Bowman gave the following explanation at the hearing:

22 When one is setting the level of the appropriation for the reserve for injuries and
23 damages, the first thing you need to look at is what is the balance in the reserve
24 for injuries and damages as of the time you start the test year and what is the level
25 of charges you expect to occur to the reserve for injuries and damages during the
26 test years and going forward?

27 The balance that we had before us at that time was \$2.6 million or two point five
28 seven nine (2.579), as shown in this table at the end of '05/'06, and the analysis,
29 looking at the five (5) year average of charges, was that in any given year the
30 average charge to the account would be about eight hundred and ten thousand
31 dollars (\$810,000) a year.

32 Now, in this application, as we've already reviewed, NTPC is proposing to change
33 the level -- the cutoff for the level of -- of charges that can occur to this fund. It
34 previously was any -- any event over five thousand dollars (\$5,000). NTPC is

⁸⁷ Ex. 2, p. 3-10, lns. 1-6.

⁸⁸ Ex. 2, p. 6-4, lns. 3-4 and attached RFID policy.

⁸⁹ Tr. I, p. 141, ln. 17 to p. 142, ln. 2.

⁹⁰ Tr. I, p. 150, lns. 17-23.

1 proposing to change that to any event over a hundred thousand dollars (\$100,000)
2 to solve some of the problems we talked about earlier.

3 As a result of that, the eight hundred and ten thousand (810,000) forecast based on
4 past practice, was -- was not relevant. What we needed to do was look at what is
5 the forecast if one does this change and adopts the hundred thousand (100,000)
6 cutoff.

7 And as a result of taking those past charges over the past five (5) years and, I
8 mean, 2001/'02 to 2005/'06, and breaking them down between those that were
9 above a hundred (100) and those that were below a hundred (100), the averages
10 that we came to were four hundred and ten (410) of the eight hundred (800)
11 related to the big charges. And four hundred (400) of the eight hundred (800)
12 related to the small charges.

13 So since we're changing the policy to go to the big cutoff, the hundred thousand
14 (100,000) plus cutoff, the forecast for '06/'07 and '07/'08, you will see there for the
15 expectation of charges to the fund, and that's at -- a long-term average, is the four
16 hundred and ten thousand (\$410,000) dollars.

17 Now, if one set an appropriation at four hundred and ten (410), the basic premise
18 would be the fund would hold steady. You would have a keep up type of -- of --
19 of appropriation.

20 But of course, the -- the intent isn't for the fund to sit at \$2.6 million and hold
21 forever, its intention were to balance and, so, what the Corporation did then was
22 take the 2.6 million that existed at the time, divided it by ten (10), so that by ten
23 (10) ten years in -- on a forecast basis, it would -- it would pull itself back to zero
24 (0) and come up with two hundred and sixty thousand (260,000).

25 So two (2) of the forecast charges of four hundred and ten (410,000), it added an
26 additional two hundred and sixty (260) which is the catch-up portion, if you pay
27 down the balance portion, and to come up with the appropriation of six seventy
28 (670).⁹¹

29 The Corporation submits that the balances in the RFID and the requested annual appropriation
30 are reasonable and should be approved.

31 **(ii) Employee Future Benefits**

32 The 2001/03 Phase I Negotiated Settlement required the Corporation to reflect the recorded
33 liability for employee future benefits (or termination costs) as at March 31, 2001 as a source of
34 no-cost capital. In addition, the settlement required NTPC to record the liability as a deferral
35 account to the benefit of ratepayers and to use this deferral account to pay for costs incurred in
36 respect of employee termination. The deferral account was not to have any appropriation until
37 such time as the then existing balance was drawn down at which point it was understood that the
38 costs would be recovered on a "pay-as-you-go" basis. NTPC has since determined that an

⁹¹ Tr. II, p. 97, ln. 4 to p. 99, ln. 11.

1 additional amount for “ultimate removal”, previously recovered as an operations and
 2 maintenance expense, should now instead be included as part of the Employee Future Benefits
 3 liability.

4 The accounting treatment required for this deferral account, as well as the expenses and
 5 adjustments to the account, were described in the Application at pages 6-54 through 6-56.⁹² The
 6 balance in the deferral account is such that there is no need to incorporate an appropriation to the
 7 account in the test year revenue requirements. Mr. Bowman described this treatment during the
 8 hearing.

9 This isn’t quite a deferral account in the sense that the others we talk about are.
 10 This is a -- a liability the Corporation must record. The basis for that liability is
 11 the present value of future benefits it’ll have to pay out to its employees based on
 12 who’s there and the terms of its agreement and how long those employees have
 13 been there and it’s audited every year.

14 In the last negotiated settlement, customers expressed an interest in not funding, if
 15 you like, that liability as the employees worked for the Corporation but instead
 16 doing it on a pay-as-you-go basis will -- building it into revenue requirement at
 17 the time the employees leave.

18 And so as a result, they said amounts set aside to that date they would like to see
 19 cashed out, if I can use the term, before they would start the pay-as- you-go
 20 approach. So it’s – it’s not a deferral account in the -- in the sense that -- that
 21 we’re talking about others here.

22 It does -- it does -- it – it’s actually drawing down a balance that was there and
 23 once that hits zero (0) then -- then the Corporation will have to address how it can
 24 set rates based on this pay-as-you-go approach that the -- that the customers asked
 25 for in the last negotiated settlement.

26 We haven’t reached that point, thankfully, because it’s -- it will probably get quite
 27 complicated when we do.⁹³

28 The Corporation submits that this treatment is consistent with the 2001/03 Phase I Negotiated
 29 Settlement and should be approved.

30 (iii) Reserve for Future Removal and Site Restoration

31 In the past NTPC has recorded a provision for the future removal of assets and site clean up costs
 32 for the majority of its assets. This treatment was supported by GAAP and approved by the PUB
 33 as forming part of the Corporation’s fixed asset amortization rates during the review of the
 34 Corporation’s depreciation studies. Changes to GAAP in the last few years now require the
 35 recording of a liability only in cases where there is a “legal obligation” for the asset disposal or
 36 site clean up and to reverse to equity any other retirement obligation liabilities. NTPC will
 37 continue with its past practice of maintaining a liability (the Reserve for Future Removal and

⁹² Ex. 2.

⁹³ Tr. II, p. 55, ln. 22 to p. 56, ln. 24.

1 Site Restoration) in order to ensure fair intergenerational allocation of costs.⁹⁴ As discussed in
2 section 8(c) below, NTPC seeks the Board's approval to continue this accounting treatment.

3 During the course of the hearing, the issue of the \$12.9 million net present value of soil
4 remediation costs discussed in the Biogenie report and how it relates to the types of costs
5 intended to be recovered from the Reserve for Future Removal and Site Restoration was
6 canvassed by counsel for the Hydro Communities. Mr. Bowman provided the following
7 explanation:

8 [w]e can confirm that NTPC has had a study done, a copy of that study was made
9 available, and it's -- the analysis in that study indicates that were one to set out --
10 as I recall it's 2005/'06 -- to do all of the cleanup that relates to fuel contamination
11 that currently exists at NTPC's various sites, that -- that the cost to remediate all
12 of that would be \$12.9 million.

13 I just say it very carefully that was because sometimes when people get into
14 talking about these costs, they get into making a plan for when that would be
15 carried out and they will inflate the dollars back or present value of them back to
16 the current day and do a bit of other math on them and -- depending if you're
17 talking about an asset retirement obligation or different ways of talking about
18 these costs.

19 The \$12.9 million is a one-time cost were NTPC to deal with all of those sites and
20 had the ability to deal with them at a -- at a -- at the day that study was done,
21 which is in 2005 dollars. And it's -- and I'm -- I'm told that it's based on a
22 desktop study. It's not necessarily based on -- on detailed travel to those
23 communities.

24 That soil remediation expense and that -- that future amount that will be spent
25 would comprise one aspect of what NTPC maintains an overall reserve for future
26 removal and restoration; that -- or sometimes called a net salvage count.

27 The overall reserve for future removal and restoration, though, includes quite a
28 broader scope than just cleaning up soil. It includes any -- any activities needed
29 to take down, remove of, ship out all the assets that are currently in place as of
30 the date that they are expected to be taken out of service, and as well as less any
31 amount expected to be recovered by selling off the parts for salvage.

32 That account I'm talking about, the reserve for future removal and restoration, is a
33 component of the Corporation's amortization. It's a component of the
34 amortization study that's conducted, and it forms a part of the depreciation rates
35 approved for the Corporation.

36 And that count, right now, has a -- a -- this is in BR-16 -- it has a -- a -- a given
37 balance in it that is approaching \$40-odd million. Out of that account, NTPC
38 does all of the spending for its activities to -- for all -- all the things I just

⁹⁴ Ex. 2, p. 3-22, ln. 21, to p. 3-23, ln. 4.

1 described: clean up soil, take down plants, ship out old engines, take down
2 transmission lines, sell materials for -- for scrap.⁹⁵

3 Counsel for the Hydro Communities also examined how the test year forecasts for spending
4 charged against the Reserve for Future Removal and Site Restoration were determined and had
5 the following exchange with Ms. Goucher.

6 MS. JUDITH GOUCHER: The six hundred thousand dollar (\$600,000) budget in
7 the test years relates to planned spending on soil remediation projects. The
8 priority of those projects is really tied to whether or not, first of all, there's any
9 third parties impacted by any contaminated soil. So those are the ones that we
10 look at first and, for example, Aklavik and Tuktoyaktuk, are two (2) cases there.

11 So we have identified -- I think we've started cleanup in Aklavik and also
12 Tuktoyaktuk. These are the remaining costs associated with those clean --
13 cleanup activities. In Fort Resolution, we've built a new plant and so there is
14 some cleanup; although, not abandonment of the old site in terms of hazardous
15 materials.

16 In Fort McPherson there are a few residual soil remediation costs related there.
17 That might be glycol related if I -- if I'm correct. And in Lutsel K'e, this is one
18 that we have budgeted for and it's related to contamination, actually on the
19 Corporation's plant site and the risk of water receptors nearby is what's prompting
20 that one; the same is the case in Yellowknife, which is for Jackfish.

21 So on that basis of, what are the water receptors, are the third parties involved,
22 and what is the -- the product involved, I guess, would be another motivator in
23 terms of identifying the priority of the sites to be cleaned up and the method of
24 cleanup.

25 MR. TOM MARRIOTT: Okay. So you've told me how you're prioritizing what
26 needs to be cleaned up first, I guess. What I'm trying to get at is whether the plan
27 is to spend this money that's needed to be spent for a mediation, the 12.959
28 million that's been estimated, basically spread out over a number of years in -- in
29 some sort of planned schedule. What we thought it might be was six hundred
30 thousand (600,000) per year over twenty- one (21) or so years. But if your
31 answer is no, that's not what you're doing, then if you can just say that directly I
32 think that would assist me.

33 MS. JUDITH GOUCHER: No, that is not the case. The six hundred thousand
34 dollar (\$600,000) planned spending in the test years is for specific projects that
35 meet the priorities, as I've laid them out.

36 It's not a -- an average amount to be spent over however many years, to clean up
37 the total of the \$12.9 million. The Corporation only cleans up its own sites as
38 they get to the end of their useful lives unless as I've mentioned there's a risk of

⁹⁵ Tr. I, p. 176, ln. 20 to p. 178, ln. 18.

1 water receptors nearby in which case offsite migration of the diesel fuel could
2 cause harm to a third party or water receptor.

3 So if it needs to be done on an urgent basis, it will be budgeted for in the fiscal
4 year but there is no planned six hundred thousand dollars (\$600,000) of spending
5 over the next several years to work our way through the \$12.9 million in total soil
6 contamination that's identified.⁹⁶

7 Finally, counsel for the Hydro Communities asked whether there was any plan to continue
8 discussions with the Federal Government to see if the Federal Government will contribute to the
9 costs of site clean-up. Ms. Goucher replied:

10 [t]he Corporation has made attempts on several occasions to approach the Federal
11 Government to see if they would be able to contribute funds towards the cleanup
12 of the soil contamination that you've referred to.

13 We've also combined our efforts with other northern utilities such as the Nunavut
14 Power Corporation. And we've also been watching with keen interest attempts by
15 the Yukon Energy Corporation to do the same thing. To date we have been
16 unsuccessful despite attempts.

17 And at the present time there -- we are not aware of any Federal programs under
18 which the Corporation might apply and qualify in order to get that funding. So at
19 this point we are still monitoring the situation.

20 I won't say that we've stopped dialogue all together but we have been turned
21 down officially. There is no current program in place that would cover this type
22 of expenditure and -- however we are, as I said, watching what's going on with
23 Yukon Electric Company and if they are successful in their attempts, theirs is so
24 much -- somewhat narrower in scope than ours, then we will definitely use that as
25 an opening and a precedent to pursue the Federal Government further.

26 But at this point the Corporation has taken it as far as it can.⁹⁷

27 The Corporation submits that its proposal to continue the accounting treatment of the Reserve for
28 Future Removal and Site Restoration is to the benefit of ratepayers and should be approved. The
29 Corporation also submits that its forecasts for costs to be charged against the Reserve are
30 reasonable and should be approved.

31 **(f) Return on Rate Base**

32 **(i) Cost of Debt**

33 NTPC's cost of debt is 10.53% and 10.93% for test years 2006/07 and 2007/08 respectively.
34 The cost of debt is calculated as follows:

⁹⁶ Tr. I, p. 182, ln. 1 to p. 184, ln. 8.

⁹⁷ Tr. I, p. 185, ln. 16 to p. 186, ln. 16.

Interest on Outstanding Debt Plus Amortization of
Financing Costs less Forecast Sinking Fund Earnings
 Gross Proceeds of Debt Issues less Unamortized Debt
 Financing Costs less Sinking Funds

1 The calculation of the cost of debt is consistent with Board Decision 1-91 in which the Board
 2 stated that the cost of debt should be calculated as “the sum of the annual debt cost and the
 3 amortization of offering discount, underwriting discount and related expenses for each long term
 4 debt issue, divided by the average net proceeds for each long term debt issue”,⁹⁸ as the numerator
 5 of the formula provided above is equal to the annual debt cost, and the denominator is equal to
 6 the average net proceeds. It is also follows the same principles applied by NTPC and accepted
 7 for purposes of the negotiated settlement in the 2001/2003 GRA approved by the Board in
 8 Decision 1-2002.

9 The witnesses for the Hydro Communities recommend that the Board set the embedded cost of
 10 debt at 8.29% for 2006/07 and 8.31% for 2007/08. The witnesses calculate the cost of debt as
 11 the total interest expense on the outstanding principal of the debt (ignoring the sinking fund
 12 earnings) plus amortization of the financing costs divided by the weighted average balance of the
 13 outstanding principal (ignoring the balance in the sinking funds as well as the cumulative
 14 recovery of the financing costs).⁹⁹

15 The methodology proposed by the Hydro Communities’ witnesses is neither fair nor reasonable
 16 and would not permit the Corporation to earn its allowed return on the equity portion of its rate
 17 base.¹⁰⁰

18 The Hydro Communities’ witnesses take the position that their cost of debt methodology should
 19 be adopted for several reasons. First, they argue that the Corporation’s methodology is
 20 inequitable by its construction. Ms. McShane demonstrated clearly why that is not the case.¹⁰¹
 21 Ms. McShane did recommend that NTPC amend its methodology slightly to recognize that
 22 sinking fund contributions are made throughout the year.¹⁰² In cross-examination, the
 23 Corporation agreed to the change proposed by Ms. McShane.¹⁰³

24 Second, the Hydro Communities’ witnesses alleged that the Corporation could have issued debt
 25 with less stringent sinking fund provisions due to the existence of the guarantee of the GNWT
 26 and the implicit federal government guarantee, and the GNWT’s Moody’s rating.¹⁰⁴ The
 27 witnesses ignore the fact that when NTPC raised the sinking fund debt, NTPC was a relatively
 28 unknown entity to potential investors and had virtually no track record. The GNWT had not
 29 raised debt for its own account and did not have a debt rating. The GNWT has only had a debt
 30 rating since 2005. It would be unreasonable to have expected potential investors to lend funds to

⁹⁸ Ex. 12, McShane Rebuttal Evidence, p. 11, lns. 309-11.

⁹⁹ Ex. 8, Drs. Kryzanowski and Roberts Testimony, p. 108; Ex. 12, McShane Rebuttal Evidence, p. 3.

¹⁰⁰ Ex. 12, McShane Rebuttal Evidence, p. 3, lns. 65-78; Tr. II, p. 245.

¹⁰¹ Ex. 12, McShane Rebuttal Evidence, p. 4, lns. 86-156 and Schedules 1 and 2.

¹⁰² Ex. 12, McShane Rebuttal Evidence, lns. 160-64.

¹⁰³ Tr. II, p. 240, ln. 3 to p. 241, ln.3.

¹⁰⁴ Ex. 8, Drs. Kryzanowski and Roberts Testimony, p. 94.

1 the Corporation on the same terms and conditions during the period in question (1989-1998) as
 2 to firms with greater market standing.¹⁰⁵ It is perhaps obvious that potential investors did not
 3 view the debt of NTPC as carrying an implicit federal government guarantee, because, if they
 4 had, NTPC should have been able to raise debt at the same rate and under similar terms and
 5 conditions as the federal government.

6 As the Corporation stated in its Rebuttal Evidence:

7 ...in each case NTPC's debt was placed in an arms length third party transaction
 8 using professionals in institutional lending, who marketed the borrowing to a
 9 number of potential lenders. The ultimate placement terms and rates reflect what
 10 the market required in the particular circumstances of NTPC at the time. At the
 11 time this debt was issued NTPC was restricted in its options for placing debt
 12 essentially to insurance companies. Particularly in the late 1980s and 1990s
 13 insurance companies had ample opportunity to purchase government debt
 14 reflecting the underlying deficits occurring in many provinces and with the
 15 Federal government at the time. Consequently the universe of potential
 16 purchasers interested in purchasing NTPC's debt offerings was very limited.¹⁰⁶

17 NTPC provided evidence regarding the early sinking fund borrowings (1989, 1991, 1992) that
 18 strongly supports a conclusion that these borrowings were fairly priced in the marketplace, given
 19 the terms and the credit quality of NTPC and GNWT at that time. This includes the fact that
 20 these were open market arms-length transactions, with a third party lender, and with NTPC being
 21 advised by professionals in this field. Against this backdrop, the standard that must be met to
 22 assert, nearly 20 years later, that these transactions somehow did not represent fair terms or rates
 23 for the borrowing is very high. NTPC submits that Dr. Kryzanowski's evidence clearly does not
 24 meet this standard, particularly given Dr. Kryzanowski was not a participant in the lending
 25 transactions in question.

26 In addition, as stated in the Rebuttal Evidence of Ms. McShane:

27 [m]oreover, the implication [made by the Hydro Communities' witnesses] that
 28 NTPC did not actively seek to obtain the most cost-effective long-term financing
 29 available on behalf of ratepayers is unwarranted. Further, each of the sinking
 30 fund issues that was issued by NTPC while under Board regulation was subject to
 31 Board review and approval. From the perspective of regulatory fairness alone, it
 32 would be unreasonable to revisit the terms and conditions of bonds that were
 33 issued up to 17 years ago.¹⁰⁷

34 The Hydro Communities witnesses then contend that NTPC followed an imprudent investment
 35 policy with respect to investment of its sinking fund contributions.¹⁰⁸ The Corporation
 36 respectfully disagrees. The Corporation followed the law. The *Financial Administration Act*
 37 prior to Bill 9 limited the eligible investments for NTPC's sinking funds and NTPC invested the

¹⁰⁵ Ex. 12, McShane Rebuttal Evidence, p. 7, ln. 195 to p.8, ln. 213.

¹⁰⁶ Ex. 12, NTPC Rebuttal Evidence, p. 1, lns. 23-30.

¹⁰⁷ Ex. 12, McShane Rebuttal Evidence, p.8, lns. 221-26; Tr. II, p. 340-43.

¹⁰⁸ Ex. 8, Drs. Kryzanowski and Roberts Testimony, p. 101; Tr. II, p. 343.

1 sinking funds accordingly.¹⁰⁹ The range of eligible investments available prior to Bill 9 is
2 virtually identical to the range of eligible investments that are still available to all other Canadian
3 utilities with sinking funds.¹¹⁰

4 While the proclamation of Bill 9 (which NTPC actively pursued) did broaden the range of
5 eligible investments for the sinking funds, the objective of the sinking funds did not change – the
6 goal is to ensure that when the sinking fund debt matures, there are sufficient monies in the funds
7 to retire the outstanding debt when it matures. Thus, while the range of eligible investments has
8 been broadened and the sinking fund policy has been amended to allow for allocation of amounts
9 in the funds to that broader range of eligible investments, the Corporation and its sinking fund
10 managers would be remiss if the level of risk exceeded the level appropriate for the funds’
11 objective.¹¹¹

12 Further, as Ms. McShane indicated in her rebuttal evidence, the fact that the Corporation
13 followed the prescriptions of the *Financial Administration Act* does not have a material impact
14 on the current calculation of the embedded cost of debt since the current sinking fund balances
15 would be approximately the same irrespective of past investments.¹¹² The sinking fund balances
16 are the result of both sinking fund earnings and sinking fund contributions. The contributions,
17 which come from the Corporation’s cash flows, not through rates, are adjusted each year in light
18 of forecast sinking fund earnings to ensure that the fund balances will be sufficient to retire the
19 debt.

20 The witnesses for the Hydro Communities also allege that the sinking fund earnings forecasts for
21 the test periods are too low. The forecasts of sinking fund returns appearing in the Hydro
22 Communities’ evidence are incorrect and understated.¹¹³ As the Corporation explained:

23 NTPC’s forecast of sinking fund returns is based on market forecasts from 2005
24 when the 2006/07 budgets were being prepared. Similar to other items in NTPC’s
25 budgets, these were not continually updated during the GRA preparation, with the
26 notable exception of including 2005/06 actual results into the 2006/07 opening
27 balances. As a result of the 2005/06 closing balances being higher than was
28 forecast at the time the 2006/07 budget was prepared, the GRA is based upon
29 forecast sinking fund earnings that are greater than NTPC’s budgets for the test
30 year 2006/07 by approximately \$265,000...¹¹⁴

31 The witnesses point to a single regulatory precedent in support of their proposed methodology, a
32 decision by the Public Utilities Board of Alberta in 1989. This decision, rendered some 18 years
33 ago, appears to be the only decision rendered by that regulator on the issue.¹¹⁵ The Corporation
34 agrees with Ms. McShane’s evidence in this regard; that is, if this Board is going to look at

¹⁰⁹ Ex. 12, McShane Rebuttal Evidence, Ins. 228-39.

¹¹⁰ Ex. 12, McShane Rebuttal Evidence, p. 9, Ins. 234-39 and Schedule 4.

¹¹¹ Tr. II, p. 192, ln. 22 to p. 143, ln. 21.

¹¹² Ex. 12, McShane Rebuttal Evidence, p. 9, Ins. 246-51.

¹¹³ Ex. 12, NTPC Rebuttal Evidence, p. 2, ln. 24.

¹¹⁴ Ex. 12, NTCP Rebuttal Evidence, p. 3, Ins. 1-8.

¹¹⁵ Ex. 12, McShane Rebuttal Evidence, p. 10, Ins. 272-74.

1 regulatory precedents, it should look at those made by regulators who regularly deal with similar
 2 sinking fund debt. Ms. McShane identified four different jurisdictions where the treatment of
 3 sinking fund debt in the calculation of the embedded cost of debt is currently the same as the
 4 method used by NTPC.¹¹⁶ In each of those four cases, the matter has been addressed more
 5 recently than the 1989 Alberta PUB case, involved a vertically integrated Crown utility similar to
 6 NTPC and only the most recent decisions from each jurisdiction were cited notwithstanding that
 7 the methodologies are long-standing.¹¹⁷ No jurisdictions were identified where a different
 8 methodology is employed. Dr. Kryzanowski agreed with Ms. McShane.¹¹⁸ In cross-
 9 examination, Mr. Williamson asked Dr. Kryzanowski if he were able to provide any examples
 10 where the method used by the Alberta Board in the case of Edmonton Power is used in other
 11 jurisdictions in Canada. Dr. Kryzanowski responded “I’m not. I haven’t done a detailed
 12 study.”¹¹⁹

13 Finally, the Hydro Communities’ witnesses recommend that, if the Board does not accept their
 14 proposed embedded cost of debt methodology, the Corporation should bear 100% of the shortfall
 15 in investment returns below a benchmark that reflects the universe of investments available and
 16 share any upside with investors.¹²⁰ Such a proposal would be unreasonable not only because it is
 17 asymmetric but also because it could, as Ms. McShane testified, produce perverse results.¹²¹ It
 18 would be imprudent, for example, to expect the Corporation to invest funds in risky equities that
 19 are set aside to retire debt that is due to mature in the relatively near-term (2009, 2011).

20 Ms. McShane also pointed out in her Rebuttal Evidence that the methodology proposed by Drs.
 21 Kryzanowski and Roberts would put the utility’s return on equity at risk, a risk for which the
 22 utility has never been compensated.¹²² In cross-examination, Mr. Retnanandan suggested that
 23 utilities with no sinking fund debt (i.e., either amortizing debt or debt with a bullet payment)
 24 were equally at risk, since they might not be able to generate the cash flows necessary to pay off
 25 the debt when it came due.¹²³ NTPC submits that the circumstances of a utility with no sinking
 26 fund requirements are quite different from its own. It is not solely a question of having sufficient
 27 funds available to pay off the debt when it comes due, it is also a question of being able to earn
 28 the allowed return on equity from year to year. As Ms. McShane pointed out, unless NTPC is
 29 allowed to recover its net interest (interest on outstanding debt less earnings on sinking funds), it
 30 will not be able to earn a return on its regulated equity equal to the allowed return.¹²⁴ A utility
 31 with no sinking funds can by definition recover its full interest expense and have the opportunity
 32 to earn its allowed return on regulated equity since the all of the utility assets are financed by the
 33 outstanding debt and equity and allowed to earn the approved return on rate base.

¹¹⁶ Ex. 12, McShane Rebuttal Evidence, p. 10, ln. 289 to p. 11, ln. 302.

¹¹⁷ Ex. 7, BR.NTPC-17, (c).

¹¹⁸ Tr. II, p. 345.

¹¹⁹ Tr. II, p. 346, ln. 23 to p. 347, ln. 3.

¹²⁰ Ex. 7, BR.HC-7.

¹²¹ Ex. 12, McShane Rebuttal Evidence, p. 12, ln. 333 to p. 23, ln. 351.

¹²² Ex. 12, McShane Rebuttal Evidence, p. 3, lns. 65-75.

¹²³ Tr. II, p. 245.

¹²⁴ Tr. II, p. 245.

1 With respect to the risk of not having generated sufficient cash flows to pay off the debt when it
2 comes due, only a utility with a sinking fund requirement has an obligation to have generated
3 those cash flows over the life of the bond. If, instead, the debt is amortizing debt or debt with a
4 bullet requirement, the utility can simply repay the maturing debt when it comes due by issuing
5 the same amount of new debt.¹²⁵ Thus the utility with no sinking funds is not exposed to the risk
6 of not generating sufficient cash flows to pay off the maturing debt.

7 In summary, the Corporation's proposed methodology allows the recovery of its prudently
8 incurred interest expense and provides it the opportunity to earn its allowed return on the equity
9 portion of its rate base. In contrast, the methodology proposed by the Hydro Communities'
10 witnesses puts the utility at risk for changes in capital market conditions and available
11 investments between the time the sinking fund debt was issued and the time the sinking fund
12 contributions are made and invested. This is a risk that NTPC has never been compensated for.
13 Moreover, it imprudently incents the utility to chase higher returns (with correspondingly higher
14 risk) in order to achieve an equity return equal to the allowed return. The sinking funds are a
15 required component of the issued debt. NTPC only invests in the sinking funds as as part of its
16 provision of regulated service, thus they form a valid component of the Revenue Requirement
17 calculation. NTPC submits that the Hydro Communities' cost of debt methodology be rejected.

18 (ii) Capital Lease

19 NTPC is proposing a cost rate for the Snare Cascades capital lease of 9.69% in 2006/07 and
20 9.70% in 2007/08. The proposed cost rate represents the terms of the Power Project Agreement
21 between NTPC and Dogrib Power Corporation that was signed in 1995. The capital costs that
22 NTPC incurs with respect to the lease represent DPC's costs of financing. Those costs are
23 comprised of DPC's actual cost of debt raised to finance the construction of the project (9.6% on
24 93.26% of DPC's capital structure) and a return on DPC's equity position in the project (NTPC's
25 allowed return on equity less 0.25% on 6.74% of DPC's capital structure).

26 The Hydro Communities' witnesses recommend that the Board set the cost of the lease for
27 revenue requirement purposes at 8.19% for 2006/07 and 8.24% for 2007/08. Drs. Kryzanowski
28 and Roberts generate these costs using the same embedded costs of debt that they recommend for
29 the debt component of NTPC's capital structure (8.29% and 8.31% for 2006/07 and 2007/08
30 respectively) for the debt component of DPC's capital structure and their recommended returns
31 on equity (6.75% and 7.20% for 2006/07 and 2007/08 respectively) for the equity component.¹²⁶
32 Acceptance of the Drs. Kryzanowski and Roberts' recommendations with respect to the capital
33 lease would be unreasonable on several levels.

34 It is unclear from Dr. Kryzanowski's testimony whether or not he had read the Capital Lease
35 prior to forming his opinion and making his recommendations.¹²⁷ In any event it is clear that Dr.
36 Kryzanowski did not find it necessary to understand the background to the Capital Lease or the

¹²⁵ Tr. II, pp. 244-45.

¹²⁶ Ex. 8, Drs. Kryzanowski and Roberts Testimony, Schedule 5.5.

¹²⁷ Tr. II, pp. 304-08.

1 factual context of the agreement before forming an opinion as to the reasonableness of passing
2 the costs on to customers.¹²⁸ As NTPC explained:

3 From a public interest perspective, the capital lease with DPC represents a cutting
4 edge relationship between a public utility and a First Nation in Canada. No other
5 public utility NTPC is aware of has to date managed to structure a deal that allows
6 for full ratepayer benefits from development of a generation project simultaneous
7 with 100% community ownership. If retroactive adverse impacts arise with
8 respect to DPC's finances from this proceeding, NTPC has significant concern
9 that any future opportunities to develop hydro in NWT will be near impossible as
10 they entail unacceptable counter-party risks for the local communities in
11 question.¹²⁹

12 These important public interest concerns were reinforced through the powerful presentation
13 made by the DPC.¹³⁰

14 With respect to the debt cost, Drs. Kryzanowski and Roberts have clearly misunderstood how the
15 interest component of the capital lease payments was determined. It does not, as the witnesses
16 speculated, represent some weighted average of NTPC's embedded debt cost of its outstanding
17 debt at the point in time that the lease was entered into. The witnesses' speculation as to what
18 the cost of debt in the capital lease represents was unnecessary as that information was available
19 in the Corporation's 2005/06 Annual Report requested by the Hydro Communities¹³¹ and filings
20 in NTPC's 1995/98 GRA. The speculation was also just plain wrong. The cost of debt in the
21 capital lease represents the actual cost of the debt that was loaned to DPC by NWT Energy.
22 NTPC simply reimburses DPC for its actual debt costs as called for under the Agreement.
23 Moreover, there is no credible evidence that the cost of debt that NWT Energy raised and loaned
24 to DPC was too high given capital market conditions at the time it was raised. As demonstrated
25 in Ms. McShane's rebuttal evidence,¹³² the cost rates of the three issues were well in line with
26 the rates available to a utility with a debt rating in the BBB category.

27 With respect to the return on DPC's equity component, the Agreement calls for the return to be
28 equal to NTPC's allowed return on equity less 0.25%. The return on the equity component of
29 the lease should adhere to the provisions of the Power Project Agreement. Section 4(f)(iv) of
30 this Argument speaks to what a fair and reasonable return on equity is for NTPC.

31 It bears noting that the costs of the capital lease were reviewed by the Board in Decision 1-97
32 (January 14, 1997), where the Board found them to be reasonable for this portion of the capital
33 lease. NTPC agrees with Ms. McShane that "a retrospective reconsideration of the prudence of
34 the capital lease arrangement entered into by NTPC more than 10 years ago constitutes
35 retroactive ratemaking."¹³³

¹²⁸ Tr. II, pp. 304-05.

¹²⁹ Ex. 12, NTPC Rebuttal Evidence, p. 4, lns. 2-8.

¹³⁰ Tr. II, pp. 158-72.

¹³¹ Ex. 7, HC.NTPC-1(b).

¹³² Ex. 12, McShane Rebuttal Evidence, p. 21, ln. 611 to p. 23 ln. 655.

¹³³ Ex. 12, McShane Rebuttal Evidence, p. 22, lns. 618-20.

1 Further, the Board should reject Drs. Kryzanowski and Roberts' assertion that the fact that the
 2 capital lease contains an equity component understates NTPC's actual equity ratio.¹³⁴ The equity
 3 return component of the lease has absolutely no bearing on NTPC's equity ratio. The small
 4 equity return component of the lease flows in its entirety to DPC. There is no portion of the
 5 equity component of the lease that flows to NTPC, NWT Energy or any other affiliated entity.¹³⁵
 6 Consequently, Dr. Kryzanowski's assertion that a case can be made that "if part of it's based on
 7 an equity rate then you can't treat the full lease as being debt"¹³⁶ is blatantly incorrect. It is
 8 100% debt from the perspective of the lessee, NTPC and its auditors under GAAP. Similarly,
 9 there is no basis for the witnesses' contention that somehow NTPC gains from the regulatory
 10 process as a result of the structure of the capital lease.

11 More broadly, the recommendations of the Hydro Communities' witnesses ignore the benefits
 12 that have accrued to customers as a result of the development of the Snare Cascades hydro
 13 project. The Corporation's rebuttal testimony attests to the level of cost savings that have been
 14 achieved and passed through to customers as a result of the development of Snare Cascades.¹³⁷
 15 Further, Dr. Kryzanowski's testimony betrays a lack of appreciation of infrastructure
 16 developments in the North.

17 MR. HUGH WILLIAMSON: So I think you're telling me that when testing the
 18 reasonableness of any component of the revenue requirement -- in this case the
 19 capital lease and the costs under that lease -- it is not necessary to have an
 20 understanding of any of the benefits that the customer may have derived when
 21 you're looking at the reasonableness of passing the costs through; is that what
 22 you're saying?

23 DR. LAWRENCE KRYZANOWSKI: If you were looking at a -- a lease
 24 decision is an alternative to debt financing, okay? So the question is, do I use
 25 debt financing or do I use leasing? That's strictly a financing decision and it's
 26 based on financial considerations. I mean, that's what corporations do when they
 27 make that type of decision.

28 Having the asset is something else. You get it whether you use debt financing or
 29 whether you use lease financing; you still get the use of the asset, so you still get
 30 the benefits from that.¹³⁸

31 The Board will appreciate that the physical ownership of infrastructure in the North is a very
 32 important decision in getting plants built and generating community support.

33 Finally, the adoption of the Hydro Communities' witnesses' recommended cost rates for the
 34 capital lease would flow through to DPC because the Agreement calls for DPC to pay to NTPC
 35 costs that are disallowed through the regulatory process.¹³⁹ It is DPC which would be negatively

¹³⁴ Ex. 8, Drs. Kryzanowski and Roberts Testimony, p. 110; Tr. II, p. 321.

¹³⁵ Tr. II, pp. 323-24.

¹³⁶ Tr. II, p. 321, lns. 5-6.

¹³⁷ Ex. 12, NTPC Rebuttal Evidence, p. 3, lns. 19-29.

¹³⁸ Tr. II, p. 309, ln. 9 to p. 310, ln. 2.

¹³⁹ Ex. 12, NTPC Rebuttal Evidence, p. 3, lns 33-35.

1 impacted if the Board were to accept the evidence of Drs. Kryzanowski and Roberts, potentially
 2 leading DPC to default on its loans. Dr. Kryzanowski appeared to recognize the serious
 3 consequences of his recommendations in responding to questions from Board consultant, Mr.
 4 Retnanandan:

5 DR. LAWRENCE KRYZANOWSKI: Well, there are -- there is the
 6 contractual obligation based on my understanding if the rate is reduced, then
 7 Dogrib would have to make up that difference, right, so it's not really violating
 8 the contract. That would be unfortunate.

9 MR. RAJ RETNANANDAN: When you say "Dogrib would have to make
 10 up the difference" in what manner" So--

11 DR. LAWRENCE KRYZANOWSKI: Well, if -- if the Board's approved
 12 rate is -- is lower.

13 MR. RAJ RETNANANDAN: Right. So -- so the Dogrib would -- would
 14 take a loss? ...

15 DR. LAWRENCE KRYZANOWSKI: Right.¹⁴⁰

16 The disallowance of costs related to an arms-length negotiated and fully implemented agreement
 17 approved by the Board would not be in the public interest, and would potentially eliminate any
 18 further opportunities to develop hydro-electric generation in the NWT on aboriginal lands.

19 **(iii) Capital Structure**

20 NTPC is proposing to use its actual capital structure as forecast for the purpose of setting
 21 2006/07 and 2007/08 rates. The capital structures, as set out in Schedule 3.5 of the Application
 22 as revised May 16, 2007,¹⁴¹ are as follows:

	<u>2006/07 Forecast</u>	<u>2007/08 Forecast</u>
Common Equity	45.53%	48.60%
Long Term Debt	44.52%	41.64%
Capital Lease Obligation	10.86%	10.60%
No Cost Capital	-0.92%	-0.85%

23 The test year common equity ratios are within NTPC's target range of 45-50% adopted by the
 24 Corporation in 1995. The target range was adopted following a study completed as a result of
 25 the Board's directive in Decision 2-94 "to review the capital structure in light of the Board's
 26 comments and to propose an appropriate capital structure consistent with NTPC's business risks
 27 at the time of its next GRA." This study was filed with the Board in NTPC's 1995/1998 GRA.

28 The proposed capital structures were reviewed by the Corporation's cost of capital expert, Ms.
 29 McShane, and determined to be reasonable in light of NTPC's stand-alone business risks, its

¹⁴⁰ Tr. II, pp. 351-52.

¹⁴¹ Ex. 13.

1 non-taxable status, interest coverage ratios and the capital structures maintained by its Canadian
2 peers.

3 The Hydro Communities' witnesses, Drs. Kryzanowski and Roberts, recommended that the
4 Board abandon its traditional practice of relying on NTPC's actual capital structures and adopt a
5 hypothetical capital structure containing 42% common equity. In the Corporation's view, the
6 proposed capital hypothetical capital structure should be rejected for several reasons.

7 First, a key component of the analysis of the witnesses for the Hydro Communities was their
8 reliance on comparisons of two benchmarks from the Alberta Generic Cost of Capital
9 proceeding. However, Dr. Kryzanowski conceded that neither he nor Dr. Roberts undertook the
10 business risk analysis in respect of the two utilities. The Board should place no weight on the
11 witnesses comparison of the business risks for NTPC to these two companies for whom someone
12 else did the business risk analysis.¹⁴²

13 Second, although the witnesses acknowledged that the Corporation is a higher risk utility than
14 the average Canadian utility, it was clear that their analysis was based on a less than complete
15 understanding of NTPC's regulatory framework. In support of their recommendation, the
16 witnesses referred to the risk mitigation of the deferral accounts maintained by the
17 Corporation.¹⁴³ In cross-examination by Mr. Williamson, it became clear that Dr. Kryzanowski
18 did not understand how some of the deferral accounts worked and that some of the deferral
19 accounts that the witnesses had characterized as mitigating risk did not, in fact, do so (e.g., the
20 Snare Cascades deferral account, financing costs, employee future benefits).¹⁴⁴ In the face of a
21 lack of understanding of the business risks faced by the Corporation, little or no weight can be
22 placed on the witnesses' relative business risk assessment for purposes of establishing the capital
23 structure.

24 Third, the witnesses ignored the impact of the non-taxable status of the Corporation. Ms.
25 McShane provided two reasons in her pre-filed evidence in support of a somewhat higher
26 common equity ratio, all other things equal, for a non-taxable corporation. Those two reasons
27 include the lower interest coverage ratios that result from the lack of an income tax cushion and
28 the higher volatility of earnings which results from not paying income tax. The EUB has
29 allowed higher common equity ratios for non-taxable utilities in recognition of these factors,
30 both for government-owned and investor-owned utilities¹⁴⁵; the CRTC has also allowed a higher
31 common equity ratio for an investor-owned telephone company when it was not taxable.¹⁴⁶
32 While the Hydro Communities stated that recent upgrades of non-taxable companies by DBRS
33 indicated that they were not concerned with their non-taxable status,¹⁴⁷ Dr. Kryzanowski could
34 not point to any non-taxable utilities that had been upgraded by DBRS.¹⁴⁸

¹⁴² Tr. II, p. 272.

¹⁴³ Ex. 8, Drs. Kryzanowski and Roberts Testimony, p. 29; Tr. II, p.252, ln. 13 to p. 253, ln. 2.

¹⁴⁴ Tr. II, pp. 273-79.

¹⁴⁵ Ex. 2, Appendix B, lns 466-70; Ex. 12, McShane Rebuttal Evidence, p. 16, ln. 472 to p. 17, ln. 478.

¹⁴⁶ Ex. 12, McShane Rebuttal Evidence, p. 17, lns. 478-81.

¹⁴⁷ Ex. 9, NTPC.HC-4.

¹⁴⁸ Tr. II, pp. 292-95.

1 Fourth, with respect to capital structures maintained by other electric utilities, Drs. Kryzanowski
 2 and Roberts did not consider the full range of electric utilities, and in fact ignored the allowed
 3 and actual capital structures of utilities that met the witnesses' own criteria.¹⁴⁹ As noted by Ms.
 4 McShane, the common equity ratios of Newfoundland Power and Maritime Electric – utilities
 5 that should have been included in the Hydro Communities' witnesses' sample – are 44.5% and
 6 42.7% respectively. These two electric utilities are both largely distribution utilities and thus of
 7 lower business risk than NTPC, which has a significant amount of generation, which is riskier
 8 than distribution.¹⁵⁰ The capital structures of both utilities, in conjunction with their lower
 9 business risk relative to NTPC and taxable status as investor-owned utilities, lend further support
 10 to the reasonableness of the Corporation's common equity ratios.

11 **(iv) Fair Return on Equity**

12 NTPC is requesting that the Board approve allowed returns on equity of 10.5% and 10.75% for
 13 test years 2006/07 and 2007/08 respectively. The requested returns on equity are supported by
 14 the expert evidence of Ms. McShane.

15 As discussed above, NTPC is entitled to the opportunity to earn a fair return on rate base as
 16 stated in section 50(1) of the *PU Act*. Ms. McShane's recommended returns on equity were
 17 developed pursuant to the three standards that govern a fair return, that is, a fair return is on that
 18 provides the utility with the opportunity to:

- 19 1. earn a return on investment commensurate with that of comparable risk
 20 enterprises;
- 21 2. maintain its financial integrity; and,
- 22 3. attract capital on reasonable terms.

23 A fair and reasonable return on equity is not the lowest possible return that the Board can allow
 24 so that the Corporation still has access to debt markets; the allowed return on equity needs to
 25 recognize the returns that are available to equity investors. The consideration of both the
 26 attraction of capital and comparable earnings standards gives rise to a range of returns. A fair
 27 and reasonable return falls within the range, neither at the lowest possible level, nor at the
 28 highest.

29 The determination of a fair return is not a simple exercise in arithmetic, although formulas for
 30 estimating the return may suggest that it is. Every test for estimating the fair return has its
 31 strengths and weaknesses and no single test should be relied upon for determining the equity
 32 return requirement. Each model is a simplification of reality whose inputs are not directly
 33 observable. To ensure that all three standards of a fair return are met, it is critical to consider
 34 various approaches to estimating a fair return.

35 Ms. McShane's recommended returns on equity are based on the application of five different
 36 tests, three risk premium tests, the discounted cash flow test and the comparable earnings test.
 37 Ms. McShane used these tests to develop a fair return on equity for a benchmark Canadian

¹⁴⁹ Tr. II, pp. 281-86.

¹⁵⁰ Ex. 2, Appendix B, pp. 414-21; Ex. 12, McShane Rebuttal Evidence, p. 14, Ins. 381-85.

1 utility, that is, a utility which, in light of its business and financial risks, would be able on a
 2 stand-alone basis, to achieve debt ratings in the A category. The returns on equity applicable to a
 3 benchmark utility would be approximately 10.0% for 2006/07 and 10.25% for 2007/08. A
 4 summary of the results of the tests applied by Ms. McShane (as updated in her Rebuttal
 5 Evidence, Ex. 12) are set out in the table below.

6	Equity Risk Premium	
7	Test Year 2006/07	9.5%
8	Test Year 2007/08	9.75%
9	Discounted Cash Flow	9.0-9.5%
10	Comparable Earnings	12.0%

11 In contrast to the approach taken by Ms. McShane, the Hydro Communities' witnesses, Drs.
 12 Kryzanowski and Roberts applied only one test, the Capital Asset Pricing Model (CAPM). They
 13 recommended returns on equity for an average risk utility of 6.75% and 7.20% for the two test
 14 years. The witnesses rely solely on the CAPM based on their belief that it has been shown to be
 15 the best test¹⁵¹ and thus no other tests – all of which they view as inferior to the CAPM – need be
 16 applied.¹⁵²

17 As Ms. McShane pointed out, Drs. Kryzanowski and Roberts' views on the CAPM are disputed
 18 by other experts in the field, both in regard to the conceptual basis and the practical
 19 application.¹⁵³ In particular, the use of a single measure of risk, beta, (that is, historic relative
 20 stock price volatility), to estimate investors' future return requirements has been soundly
 21 criticized. For example, at page 35, lines 1038-1045, of Ms. McShane's Rebuttal Testimony, she
 22 cites a widely utilized text which concludes:

23 Beta, the risk measure from the capital-asset pricing model, looks nice on the
 24 surface. It is a simple, easy-to-understand measure of market sensitivity. Alas,
 25 beta also has its warts. The actual relationship between beta and rate of return has
 26 not corresponded to the relationship predicted in theory during long periods of the
 27 twentieth century. Moreover, betas for individual stocks are not stable from
 28 period to period, and they are very sensitive to the particular market proxy against
 29 which they are measured...¹⁵⁴

30 Attachment A, page 2, to Ms. McShane's Rebuttal Evidence quotes legendary investor Ben
 31 Graham:

32 What bothers me is that authorities now equate the beta with the concept of risk.
 33 Price variability, yes; risk, no. Real investment risk is measured not by the per
 34 cent a stock may decline in price in relation to the general market in a given

¹⁵¹ Tr. II, pp. 260-61.

¹⁵² Ex. 8, Drs. Kryzanowski and Roberts Testimony, p. 42.

¹⁵³ Ex. 2, Appendix B (see Appendix A, pp. 7-10 of the Prepared Testimony of Kathleen C. McShane); Ex. 12, McShane Rebuttal Evidence, p.35, ln. 1016 to p. 36, ln. 1072 and Attachment A.

¹⁵⁴ Ex. 12.

1 period but by the danger of a loss of quality and earning power through economic
2 changes or deterioration in management.¹⁵⁵

3 While Ms. McShane applies the CAPM as one of her five tests, she correctly recognizes that it is
4 not inherently superior to any of the other tests that are available to estimate a fair return on
5 equity. She also recognizes that in principle the CAPM attempts to measure the minimum return
6 that will allow a company to attract equity capital. It does not address the broader issues of
7 whether the result, when applied to the book value of equity will allow a utility to maintain its
8 financial integrity nor does it address or measure returns actually available to enterprises of
9 similar risk. That is, it does not address the comparable earnings standard.

10 As Ms. McShane's Opening Statement noted, without the comparable earnings test, which Drs.
11 Kryzanowski and Roberts do not apply, there is no direct measure of the comparable earnings
12 standard.¹⁵⁶ Ms. McShane's comparable earnings test demonstrates that low risk unregulated
13 companies are earning returns in the 12.0% to 13.0% range, leading to the conclusion that, based
14 on comparable earnings alone, a fair return for an average risk Canadian utility of 12.0% would
15 be warranted.¹⁵⁷ A return on equity of 12.0% is quite close to the level of returns that low risk
16 U.S. utilities are expected to earn; as stated at lines 1259-1262 of Ms. McShane's Direct
17 Evidence, the expected return on equity for a sample of low risk U.S. utilities is in the range of
18 11.5-12.0%.¹⁵⁸ Nevertheless, Ms. McShane is not proposing that the return on equity for an
19 average risk utility be set at 12.0%. Her benchmark return on equity gives weight to both the
20 cost of attracting equity capital and the comparable earnings standards.

21 Ms. McShane's rebuttal evidence addresses in detail the technical issues with respect to each of
22 the cost of attracting capital tests she performed (risk premium and discounted cash flow tests),
23 and by extension the results of the Hydro Communities' witnesses' CAPM test. NTPC does not
24 intend on repeating the technical evidence in both Ms. McShane's direct and rebuttal testimony
25 that buttresses the cost of attracting equity capital estimates set out in the table above. The
26 Corporation recognizes that the Board must review the technical analysis in support of its
27 requested returns on equity, but in so doing, it should not lose sight of the less technical, but no
28 less informative, perspectives that provide a context for distinguishing between Ms. McShane's
29 benchmark utility costs of attracting equity capital of 9.25% and 9.5% and recommended
30 benchmark utility returns on equity of 10.0% and 10.25% and Drs. Kryzanowski and Roberts'
31 proposed allowed returns of 6.75% and 7.20% for 2006/07 and 2007/08 respectively.

32 Ms. McShane's recommended benchmark utility returns of 10.0% and 10.25% are higher than
33 the returns that would be allowed for the typical Canadian utility operating under an automatic
34 adjustment formula. The average allowed return for a Canadian investor-owned utility operating
35 under these formulas at the 4.65% long Canada bond yield forecast by Drs. Kryzanowski and
36 Roberts for 2007/08 would be 8.9%.¹⁵⁹ However, as Ms. McShane pointed out, the allowed

¹⁵⁵ Ex. 12.

¹⁵⁶ Tr. II, p. 181, ln. 11 to p. 187, ln. 24.

¹⁵⁷ Ms. McShane's Rebuttal Evidence addresses each of the critiques of the comparable earnings test (Ex. 12, pp. 48-54) proffered by Drs. Kryzanowski and Roberts and concludes that many of the same critiques are similarly applicable to the CAPM.

¹⁵⁸ Ex. 2, Appendix B.

¹⁵⁹ Ex. 12, McShane Rebuttal Evidence, p. 29, ln. 841 to p. 30, ln. 843.

1 returns generated by the automatic adjustment mechanisms are viewed as low by capital market
 2 participants, including the debt rating agencies, pension funds and equity analysts. (Rebuttal
 3 Testimony, lines 849-969) In particular, the allowed returns generated by the formulas are low
 4 in comparison with those of Canadian utilities' U.S. peers, whose allowed returns have recently
 5 (1st quarter 2007) have been approximately 10.3%-10.4% in relation to common equity ratios of
 6 47-48%.¹⁶⁰ Allowed returns for Canadian utilities not operating under automatic adjustment
 7 formulas have also been higher than the formula returns (Nova Scotia Power, 9.55%; Maritime
 8 Electric, 10.25%.¹⁶¹

9 As noted by the Conference Board of Canada, with specific respect to returns allowed for
 10 electricity transmission – generally viewed as exposed to less business risk than an integrated
 11 electric utility.¹⁶²

12 Investors are discouraged by limitations on the regulated cost recovery for
 13 transmission upgrading. Transmission companies are simply not seeing
 14 favourable risk/return ratios on their investments, and know that they can realize
 15 better returns in the United States, where regulated rates of return are much
 16 higher. Rates of return to Canadian firms for transmission projects are around 9
 17 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies.
 18 These lower rates discourage investment in Canadian utilities.¹⁶³

19 Further, as pointed out with specific respect to Crown Corporations by London Economics in
 20 “Paying the Full Cost of Power” (April 5, 2005):

21 ...provincial shareholders fail to demand an appropriate return on equity from
 22 their utilities. Failure to demand an appropriate equity return effectively means
 23 that the shareholder is failing to collect revenues from the electricity sector which
 24 could be used to fund social investments with possibly higher total social returns,
 25 such as investments in education, health, and regional development. A typical
 26 private integrated utility would normally be earning upwards of 12% as a return
 27 on equity, and would have a much higher proportion of equity in its capital
 28 structure.¹⁶⁴

29 These comments not only provide support for the proposition that the return on equity for NTPC
 30 should be commensurate with those allowed for investor-owned utilities, but also that the returns
 31 developed by Ms. McShane for a benchmark Canadian utility are, if anything, conservative,
 32 when compared with those of comparable integrated electric utilities.

¹⁶⁰ Ex. 12, McShane Rebuttal Evidence, p. 33, ln. 974 to p. 34, ln. 979.

¹⁶¹ Ex. 12, McShane Rebuttal Evidence, p. 30, lns. 844-46.

¹⁶² As illustrated by the EUB's Generic Cost of Capital Decision 2004-052 (July 2004) in which electricity transmission was allowed the lowest common equity ratio of all the regulated firms governed by the decision (p. 55).

¹⁶³ Conference Board of Canada, Electricity Restructuring: Opening Power Markets, May 2004; Ex. 12, McShane Rebuttal Evidence, lns. 991-98.

¹⁶⁴ Ex. 28, pp. 12-13.

1 Ms. McShane's recommended returns for NTPC of 10.5% and 10.75% are equal to the return
 2 applicable to a benchmark average risk Canadian utility plus an incremental equity risk premium
 3 of 0.50% to recognize the Corporation's higher risk relative to the benchmark (which, as noted
 4 above, is a utility with debt ratings in the A category). As set forth in Ms. McShane's direct
 5 evidence, on a stand-alone basis, the Corporation would be, on a stand-alone basis, rated in the
 6 BBB category given its business and financial risks.¹⁶⁵ Thus NTPC is of higher risk than the
 7 benchmark utility. There is no disagreement between Ms. McShane and the Hydro
 8 Communities' witnesses that NTPC is a higher risk utility than the typical Canadian utility.¹⁶⁶
 9 There is also agreement that the stand-alone principle should be applied when setting the allowed
 10 return on equity for NTPC.¹⁶⁷ The stand-alone principle holds that the return on equity should
 11 reflect the business and financial risks of the Corporation, independent of the existence and
 12 impact of the debt guarantee and debt ratings of the GNWT.

13 The estimation of the difference in return that would be warranted for NTPC's higher business
 14 risks is in part a matter of professional judgment, but should be constrained by factual support.
 15 Ms. McShane's direct evidence demonstrates that the difference in the cost of debt as between a
 16 utility with debt ratings in the A category and a utility whose debt is rated in the BBB category is
 17 approximately 0.60%.¹⁶⁸ The difference in the cost of debt between an A rated benchmark utility
 18 and a BBB rated utility (which NTPC would be on a stand-alone basis) serves as a proxy for the
 19 incremental return that an equity investor would require to invest in NTPC. On the basis of cost
 20 of debt differentials, Ms. McShane's incremental equity risk premium of 0.50% for the
 21 Corporation should be viewed as the minimal differential return required relative to a benchmark
 22 utility. Her proposed differential is fully consistent with the 0.60% differential adopted by the
 23 Board in respect of the allowed return for NUL in Decision 9-2006 (March 2006).

24 **(v) Impact of Hydro Communities' Witnesses' Cost of Capital**
 25 **Recommendations on NTPC's Interest Coverage**

26 The witnesses for the Hydro Communities have materially overstated the interest coverage that
 27 the adoption of their recommendations (capital structure, return on equity, cost of debt and the
 28 capital lease) would produce for NTPC's regulated operations. They completely ignored the
 29 capital lease payments in their calculation of the interest coverage. Since the capital lease
 30 accounts for close to 11% of NTPC's capital structure, simply including their proposed recovery
 31 of capital lease costs lowers the indicated interest coverage to well below the level that they
 32 alleged their recommendations produced, from 2 times to 1.6 times.¹⁶⁹ However, the actual
 33 interest coverage for NTPC's regulated operations would be significantly lower, since the
 34 witnesses' calculations of interest expense and interest coverage did not take into account the
 35 interest costs and capital lease costs that the Corporation will actually incur.¹⁷⁰

¹⁶⁵ Ex. 2, p. 18, lns. 476-480.

¹⁶⁶ Tr. II, p. 187, lns. 21-24.

¹⁶⁷ Ex. 2, p. 2, lns. 46-67; Ex. 8, Drs. Kryzanowski and Roberts Testimony, p. 5.

¹⁶⁸ Ex. 2, p. 18, ln. 482 to p. 19, ln. 497.

¹⁶⁹ Ex. 12, McShane Rebuttal Evidence, lns. 526-29.

¹⁷⁰ Ex. 12, McShane Rebuttal Evidence, lns. 585-96.

1 The stand-alone actual interest coverage of NTPC's regulated operations assuming (i) adoption
 2 by the Board of the witnesses' recommendations for capital structure, return on equity and costs
 3 of debt and the capital lease and (ii) taking account of the actual costs associated with both the
 4 capital lease and the outstanding debt would be only 1.43 times,¹⁷¹ compared to the recent
 5 average interest coverage ratio maintained by Canadian utilities of 2.5 times.¹⁷² The actual
 6 stand-alone interest coverage ratio that would result from the adoption of the recommendations
 7 of the witnesses with respect to capital structure, return on equity, and costs of debt and the
 8 capital lease, given the Corporation's actual costs, is so far below the average interest coverage
 9 ratios maintained by other Canadian utilities that the witnesses' recommendations that not only
 10 would the adoption of their recommendations fail to meet the financial integrity standard, their
 11 recommendations simply cannot be viewed as credible.

12 **5. Shortfall from Revenues at Existing Rates**

13 Shortfalls at existing rates are set-out in Chapter 4 of the Application. The shortfalls can be
 14 described in terms of (i) corporate wide shortfalls, (ii) shortfalls currently collected by way of
 15 riders and (iii) core shortfalls not addressed by way of existing riders. This section of the
 16 Application was provided primarily to assist the Board and intervenors in understanding the
 17 magnitude of rate increases that would be required as a result of implementing the test year
 18 revenue requirements. The Corporation is not seeking specific approval of any shortfall amounts
 19 in the Application. Following the Board's final decision on the Corporation's Phase I
 20 Application, the Corporation will apply to collect the resulting shortfall from existing and interim
 21 rates by way of temporary shortfall riders.

22 **6. Rate Base**

23 The Corporation's rate base reflects the net cost of all regulated assets that are used and useful in
 24 providing service to the Corporation's customers, including an allowance for working capital.
 25 The test year forecasts of the Corporation's rate base are set out in Chapter 5 of the Application.
 26 The Corporation is requesting approval of mid-year rate base of \$191.879 million for 2006/07
 27 and \$201.992 million for 2007/08.¹⁷³ Specific elements of the calculation of the Corporation's
 28 rate base are discussed in the following sections.

29 **(a) Gross Plant in Service**

30 Gross Plant in Service represents the accounting costs of all regulated assets in service. Actual
 31 capital additions for 2004/05 and 2005/06 and forecast capital additions for 2006/07 and 2007/08
 32 were set out in Appendix C of the Application. During the hearing Mr. Kerr provided the
 33 following discussion of the Corporation's capital planning process.

34 Just to -- to briefly explain a bit about our -- our capital planning process. The
 35 Corporation developed a five (5) year rolling capital plan and as each of those
 36 respective years becomes the -- the next fiscal year, which we're doing our
 37 planning, we review those projects and re-evaluate them and investigate them

¹⁷¹ Ex. 12, McShane Rebuttal Evidence, p. 14, lns. 529-32.

¹⁷² Ex. 2, Appendix B, p. 17, lns. 453-55 and Schedule 2.

¹⁷³ Ex. 13, Schedule 5.1 (revised May 16, 2007).

1 more thoroughly to determine the scope and the merits of the projects to ensure
 2 they're – they're worthwhile to proceed with and to ensure that the problem or the
 3 issue still exists as was potentially identified in the five (5) year capital plan.

4 The plan in itself is a fairly dynamic and -- and living document and there's
 5 changes that come along as most people can understand with any plan. And some
 6 of the reasons being for those changes are, you know; priorities change;
 7 emergencies; logistics and/or operational requirements which prevent projects
 8 from -- from being initiated or -- and/or completed as originally planned;
 9 availability of external/internal resources, and those are both personnel and -- and
 10 equipment requirements; changes in technology; equipment replacements being
 11 deferred or advanced based on priorities or changes in -- in usage or inspections;
 12 and engineering or operational judgment.

13 Now, with respect to your specific issue, is how do we deal with the variances in
 14 specific projects? Each project is undertaken with a budget developed in, I
 15 guess, the previous fiscal year, and as a project goes forward it is approved by
 16 senior management and is taken to the Northwest Territories Board of Directors;
 17 they -- they approve the annual -- the annual budget in March.

18 And estimates are done up by the engineering staff and/or contractors that are
 19 hired. As we proceed down the road with the project, we keep an eye on the cost.
 20 If we see cost overruns, these are start -- they are brought back to senior
 21 management for approval. There are job cost revision forms that are completed
 22 and need to be approved by senior management. And if the job costs revision is --
 23 is large enough, it would have to be taken back to the Board of Directors for
 24 approval.¹⁷⁴

25 Capital additions undertaken since the last GRA or forecast to be undertaken in the test years that
 26 were the subject of capital project permit reviews by the Board or that were examined during the
 27 hearing are discussed in further detail below.

28 **(i) Bluefish Generating Station**

29 The Corporation purchased the Bluefish Generating Station in the 2004/05 at a final cost
 30 (including acquisition costs) of \$11.861 million.

31 The Bluefish purchase was initially reviewed and approved by the Board during NTPC's
 32 application for a capital project permit review in PUB Decision 12-2002. The City of
 33 Yellowknife, NUL, the Village of Fort Simpson, Liidlii Kue First Nation and Hamlet of Fort
 34 Liard all participated in that proceeding. The Board reviewed the economic viability of the
 35 project to the extent necessary to conclude the project was prudent. The Board approved the
 36 Bluefish project permit and noted that "[t]he Board is satisfied that the acquisition of Bluefish is
 37 worthwhile and that it is justifiable on the merits of the project economics."¹⁷⁵ The Board also

¹⁷⁴ Tr. II, p. 122, ln. 7 to p. 123, ln. 22.

¹⁷⁵ PUB Decision 12-2002 at 7.

1 noted that the prudence of the expenditures and the impact on rates would be examined at
2 NTPC's next GRA.¹⁷⁶

3 In its capital project permit application, NTPC indicated that the cost of purchasing Bluefish
4 would be \$13.5 million, including \$1.84 million in capital spending expected by December 31,
5 2004. The actual purchase costs of \$11.861 million plus \$0.742 million in capital works
6 completed by March 31, 2005 totals \$12.603 million, or \$0.897 million less than the approved
7 project permit.¹⁷⁷

8 In response to BR.NTPC-9, the Corporation noted that at the time of the purchase, the Bluefish
9 purchase was estimated to have a positive impact for ratepayers with a net-present value of \$38.1
10 million.¹⁷⁸ Since that time, the economics of the purchase have been affected by a number of
11 factors, most notably increases in the price of diesel fuel, offset by actual and forecast capital
12 improvement costs that are higher than was anticipated at the time of the Bluefish purchase. As a
13 result of these factor, an updated project economic assessment was presented in BR.NTPC-9,
14 which indicates that the net present value benefit to ratepayers is now expected to be \$51.4
15 million (2005\$) – an increase of 35 per cent from the forecast at the time of the project permit
16 application.¹⁷⁹

17 In summary, the Bluefish project was a prudent acquisition that is providing benefits to
18 customers today and will continue to provide benefits into the future. No intervenor submitted
19 evidence to suggest that the costs of the project were not reasonable. The Corporation submits
20 that the project should be approved as part of the rate base for the test years.

21 (ii) Fort McPherson Power Plant

22 The Fort McPherson Power Plant was destroyed by fire on January 19, 2004. The Corporation's
23 emergency response to the Fort McPherson plant fire, including the use of the Corporation's
24 emergency gensets, was described in TGC.NTPC-33(e).

25 In PUB Decision 6-2004 the Board approved a project permit for the new power plant. At that
26 time NTPC provided an initial estimate of project costs of \$5.5 million to \$7 million. In a
27 subsequent update to the Board on August 19, 2004, NTPC indicated that the cost including a
28 number of betterments that were suitably included in the scope of work for the new plant was
29 estimated at \$7.4 million. The total cost of the completed project, including insurance proceeds,
30 charges to the RFID and site remediation costs, is \$2.911 million.¹⁸⁰ A detailed breakdown was
31 provided in the response to TGC.NTPC-34 (b).

32 During the hearing the TGC's consultant asked if waiving the Corporation's normal bidding and
33 tendering process was normal practice in similar circumstances. Mr. Kerr replied:

¹⁷⁶ PUB Decision 12-2002 at 5.

¹⁷⁷ Ex. 2, Application cover letter at 6 (unnumbered), footnote 10.

¹⁷⁸ Ex. 7, BR.NTPC-9: net-present value of benefits of \$59.3 million less net-present value of costs of \$21.2 million.

¹⁷⁹ Ex. 7, BR.NTPC-9: net-preset value of benefits of \$84.8 million less net-present value of costs of \$33.4 million.

¹⁸⁰ Ex. 2, Appendix C, p. C-9.

1 Sir, just to answer your question, it is not the Corporation's normal practice to go
 2 out and sole-source contracts. This was a fairly unique situation. We needed to
 3 get a power plant built. Some of the -- the tendering was invitational tendering
 4 sent to specific contractors.

5 We've done this in the past and I think another fire that occurred some years ago
 6 was at [Sanikiluaq]; a similar situation where you have to get something
 7 constructed in a hurry. You cannot sit there and go through weeks of tendering
 8 processes. You need to get power on and -- and supplies, materials, contractors
 9 set up to get this done in an orderly and -- and as quick -- as quick as you can.¹⁸¹

10 The Corporation submits that the evidence in this proceeding demonstrates that the costs of the
 11 Fort McPherson Power Plant rebuild are reasonable and were prudently incurred. Therefore all
 12 amounts included in the Application with respect to this project should be approved for inclusion
 13 in rate base.

14 **(iii) Snare Rapids Plant Upgrade**

15 The Snare Rapids Plant upgrade was reviewed and approved by the Board in Decision 8-2004.
 16 The project permit application included NTPC's proposed budget of \$4.984 million, which was
 17 specifically noted as being a "budget level" estimate and not an "engineering pre-design"
 18 estimate.¹⁸² The GRA forecast costs are \$0.159 million higher and include capital costs of
 19 \$3.838 million in 2005/06 and forecast costs of \$1.305 million in 2007/08 for total project capital
 20 costs by the end of the test period of \$5.143 million. A breakdown of the costs included in the
 21 \$3.838 million portion of the project was provided in response to HC.NTPC-60 (a).

22 The Corporation submits that the project costs included in the test period are reasonable and
 23 should be approved.

24 **(iv) L199 Recommissioning**

25 The L199 recommissioning has been the subject of several proceedings before the Board. In
 26 1999 the Corporation applied for a capital project permit application to undertake the
 27 transmission line repairs. The City of Yellowknife participated in that proceeding. In PUB
 28 Decision 1-99 the Board approved NTPC's application and noted that the regulatory treatment of
 29 the cost of the repairs, prudence issues related to the expenditure and the impact on rates would
 30 be examined at the time the Corporation filed for amended rate schedules.¹⁸³ Subsequently,
 31 pursuant to the 2001/03 GRA Negotiated Settlement agreed to defer these amounts and not add
 32 to rate base until resolution of the legal claims.¹⁸⁴

33 A confidential mediation was conducted in August 2005 and at the conclusion of the mediation
 34 the Corporation received a final settlement offer. The mediator advised that he was satisfied that

¹⁸¹ Tr. II, p. 82, ln. 19 to p. 83, ln. 7.

¹⁸² Ex. 3, YK/HR/FS-2, p. 20.

¹⁸³ PUB Decision 1-99 at 4.

¹⁸⁴ 2001/03 Phase I GRA Negotiated Settlement dated November 20, 2001, p. 2, point 3.

1 this was the best offer that would be made and if it was not satisfactory the matter would have to
2 proceed to trial.¹⁸⁵

3 Consequently, the Corporation has added \$3.068 million to rate base in 2005/06.¹⁸⁶ This amount
4 was made up of \$3.502 million in project costs plus \$0.758 million in deferral account interest
5 plus \$0.414 in legal and court costs less \$1.605 recovered through the settlement of the legal
6 claims.¹⁸⁷ The addition of the L199 recommissioning to rate base is consistent with normal
7 accounting for assets that are used, useful and in service and with the resolution of the legal
8 claims there is no further basis for retaining the deferral account. This treatment also insures that
9 no further interest accrues on the deferral account.¹⁸⁸

10 During the hearing, counsel for the Hydro Communities cross-examined on the total cost of the
11 project including the cost to re-energize the L190 transmission line. Ms. Goucher explained how
12 the total capital cost of the project in rate base was developed, with reference to HC.NTPC-
13 56(d).

14 The actual project cost including the cost to re-energize the L-190 transmission
15 line of six hundred and thirty-thousand (630,000) was 4.1 million, rounding, and I
16 get to that number by adding the six hundred and thirty-thousand (630,000) to the
17 two (2) capital amounts of -- if you follow across in the line of the year
18 2000/2001, the opening balance of 3.4 million added to that ninety-two thousand
19 dollars (\$92,000) for a total of, rounding, 3.5 million.

20 So that's how I get to my 4.1 million as the capital cost associated with this
21 project.¹⁸⁹

22 Ms. Goucher also provided the following explanation of the considerations that led the
23 Corporation to decide to accept the settlement and not pursue the matter to trial:

24 The key considerations factoring into the Corporation's decision not to pursue this
25 to -- through to trial were:

26 a) the amount of management time that this particular lawsuit or settlement
27 negotiation was taking.

28 The legal fees associated that were mounting.

29 The interest that was accruing, based on the treatment of the costs in a deferral
30 account.

31 And also, in our legal opinion, or our legal advisor's opinion, I guess concern in
32 terms of the parties to the lawsuit and whether or not they would still be around at

¹⁸⁵ Ex. 4, Undertaking #14, p. 2.

¹⁸⁶ Ex. 2, Appendix C, p. C-11.

¹⁸⁷ Ex. 3, YK/HR/FS-9, p. 26.

¹⁸⁸ Ex. 2, Appendix C, p. C-11, ln. 20 to p. C-21, ln. 3.

¹⁸⁹ Tr. I, p. 213, lns. 6-16.

1 the end of a lawsuit in order to secure a better settlement than what was achieved
2 through mediation.

3 To my knowledge, the Corporation being found negligent did not factor into that
4 decision.¹⁹⁰

5 The L199 recommissioning was a necessary and prudently incurred project following Board
6 approval. The Corporation added the project to rate base following the settlement agreement
7 consistent with the appropriate accounting and regulatory treatment of an asset that is used and
8 useful to customers. The Corporation therefore submits that amounts included in the Application
9 with respect to the L199 recommissioning should be approved as part of the Corporation's rate
10 base.

11 **(v) Aklavik Power Plant**

12 The Aklavik Power Plant was reviewed and approved by the Board in PUB Decision 11-2006.
13 That decision reviewed an estimated project budget of \$4.9 million. The Corporation's
14 Application includes forecast capital costs of \$5.298 million in the 2007/08 test year.

15 The need for the project and options considered during the planning for the Aklavik Power Plant
16 were described in detail on pages 6-44 through 6-49 and Appendix C of the Application, as well
17 as in BR.NTPC-27(c)(i) & (ii). It should be noted that the Corporation undertook extensive
18 consultation with Aklavik and that the option put forward by the Corporation has received
19 support from the community by way of a Band council motion. Therefore, the Corporation
20 submits that the project costs included in the test period are reasonable and should be approved.

21 **(vi) Automatic Meter Reading**

22 In 1996/97 NTPC undertook research and investigated the emerging technologies related to
23 Automatic Meter Reading ("AMR"). The Hunt Technologies AMR system (Turtle) used Power
24 Line Carrier to transfer data. This meant that NTPC's existing distribution system could be
25 utilized instead of 3rd party communications. To date, the installation and utilization of the
26 system has been a success. It has reduced time required to read meters, improves accuracy of
27 meter reads, and reduces administrative time for data entry and significantly reduces billing
28 errors which improves customer relations.¹⁹¹

29 The Board requested more information on studies undertaken to justify the Norman Wells AMR
30 project in 2004/05, the Fort Smith AMR project in 2005/06 and the Fort Simpson AMR project
31 forecast for 2006/07. In BR.NTPC-29(m) NTPC provided a series of net-present value analyses
32 that showed all of the projects had positive net present value under the assumptions both at the
33 time the projects were proposed and using current cost variables.¹⁹²

34 During the hearing, the TGC's consultant requested more detail with respect to the net present
35 value analysis undertaken for the Fort Simpson AMR project. The Corporation responded to this

¹⁹⁰ Tr. I, p. 216, lns. 9-25.

¹⁹¹ Ex. 7, BR.NTPC-29(m).

¹⁹² Ex. 7, Tables BR.NTPC-29(m.1) to BR.NTPC-29(m.6).

1 request in Undertaking No. 15.¹⁹³ Counsel for the Hydro Communities also asked whether there
2 was any reduction in staff levels related to meter reading or administrative data entry, to which
3 Ms. Goucher replied that "...installation of the automatic Turtle meter reading system has
4 allowed us to utilize our line persons for other line-related work, as opposed to meter reading."¹⁹⁴

5 The evidence demonstrates that the AMR projects have improved the efficiency of the
6 Corporation's operations and have a net benefit to customers. However, this does not mean that
7 staff positions can be reduced or eliminated as a result of the projects. The Corporation submits
8 that costs related to the AMR projects are reasonable and should be approved.

9 **(b) Accumulated Amortization**

10 Accumulated amortization represents the collected amortization related to all regulated NTPC
11 assets in service. Accumulated amortization balances in each year include amortization expense
12 and amortization reserve variance less disposals and site restoration spending. Accumulated
13 amortization balances for the test years were discussed on pages 5-3 through 5-4 of the
14 Application.¹⁹⁵ No intervenors submitted evidence with respect to the Corporation's calculation
15 of accumulated amortization balances for the test years. The Corporation submits that its
16 forecast accumulated amortization balances for the 2006/07 and 2007/08 test years are prudent,
17 reasonable and should be approved as applied for.

18 **(c) Customer Contributions**

19 Customer contributions represent the portion of asset costs that were recovered directly from
20 customers at the time the assets were constructed. Net customer contributions therefore are an
21 offset to rate base. Customer contributions were described at pages 5-5 through 5-6 of the
22 Application. The Corporation's forecasts for net customer contributions are \$3.505 million in
23 2006/07 and \$3.138 million in 2007/08.¹⁹⁶

24 During the hearing, several intervenors requested information on why no additions to customer
25 contributions were forecast in the test years. In response to BR.NTPC-20 (a) the Corporation
26 provided the following information:

27 Extension projects tend to be very difficult to forecast on a plant to plant basis but
28 they form a very small portion of the overall capital budget in each year. For
29 budgeting purposes the Corporation forecasts these projects on a net basis, that is
30 the amounts included in the capital budget are prepared including customer
31 contributions. Additions to customer contributions are therefore not forecast. This
32 is consistent with practice in previous General Rate Applications.

33 No intervenors submitted evidence on the topic of customer contribution forecasts. The
34 Corporation submits that its test year forecasts of net customer contributions are reasonable and
35 should be approved.

¹⁹³ Ex. 33.

¹⁹⁴ Tr. I, p. 118, lns. 22-25.

¹⁹⁵ Ex. 2.

¹⁹⁶ Ex. 13, Schedule 5.1 revised May 16, 2007.

1 **(d) Working Capital**

2 Working capital includes an allowance for cash working capital as well as balances in supplies
3 inventory; fuel and lube inventory, deferred charges, the overhaul deferral account and the
4 proposed water licensing deferral account. Working capital was discussed on pages 5-6 through
5 5-8 of the Application.

6 The cash working capital provision was calculated based on a Lead-Lag Study that used the
7 Corporation's terms and conditions and standard payment periods. During the hearing the
8 consultant for the TGC requested information on the revenue lags assumed in the Lead-Lag
9 study and had the following discussion with Mr. Bowman:

10 MR. AZAD MERANI: Mr. Bowman, I was trying to understand - and my
11 apologies for making it a long question - but TGC-46D I understood that the lag
12 days is based on the maximum allowable time for payment and what I wanted to
13 understand was if you had done any work or analysis to allow you to understand
14 whether that's realistic or not.

15 MR. PATRICK BOWMAN: The -- you're -- you're correct, the lead-lag study in
16 this application is based on the assumption that customers pay on time. There
17 was extensive work and study done in the last rate application on terms of when
18 actual payments occur. It was quite clear that there -- that -- that, first of all, it's a
19 massive undertaking to go through all of the different payments and bills that
20 occur and figure out exactly when all the customers -- different customers do pay.

21 That -- that did indicate, I think as you noted, that overall the tendencies for
22 customers to pay over the time, not -- not in advance of the time that things -- that
23 payments are due and it was not an undertaking the Corporation took in this rate
24 application because it was -- this is a simplified assumption.

25 This assumption shortens the lag days compared to what was in the last
26 application and it avoids the need to have to do such a massive undertaking every
27 -- every GRA to go through and figure out exactly when all those payments do
28 occur.¹⁹⁷

29 The TGC's consultant also asked about whether it would be more appropriate to carry through
30 the net expense lags for each component in calculating the cash working capital allowance. Mr.
31 Bowman responded:

32 I -- I suppose what you're saying is rather than coming up with an average that
33 one carries forward, derive all of the underlying numbers in the average and carry
34 each of those lag day estimates or analyses forward and apply them to the
35 category to which they relate in the test years.

36 I -- it's certainly not the basis on which the Corporation has done lead/lag studies
37 in the past. I -- I'm not sure I've -- I've seen it done quite that way but I'm

¹⁹⁷ Tr. II, p. 89, ln. 12 to p. 90, ln. 14.

1 reasonably certain that the intent would be it would be mathematically
2 equivalent.¹⁹⁸

3 The Corporation's proposal to use standardized payment periods based on its Terms and
4 Conditions of Service results in a shorter lag period than in previous rate applications and a
5 reduced overall Revenue Requirement to the benefit of customers. It also significantly reduces
6 the effort involved in preparing the Corporation's cash working capital forecast. Therefore the
7 Corporation submits that its working capital forecasts for the test years are reasonable and should
8 be approved.

9 **7. Terms and Conditions of Service**

10 Chapter 7 of the Application sets out a number of proposed revisions to the Corporation's Terms
11 and Conditions of Service ("T&Cs"). As noted in that chapter:

12 [t]he revisions applied for in this Application generally fall into one of two
13 categories: housekeeping revisions and substantive revisions. Housekeeping
14 revisions are intended to correct minor typographical, grammatical and formatting
15 errors, ensure consistent use of defined terms, delete redundant provisions and
16 clarify the existing text without altering the nature or scope of the Section.
17 Substantive revisions are intended to provide for greater clarity and consistency in
18 the Terms, making the document easier to understand by both customers and the
19 Corporation's personnel, as well as consistency with typical electric utility
20 practice. The revised Terms will enhance the Corporation's ability to meet the
21 needs of its customers and ensure fairness and consistency in the Corporation's
22 treatment of its customers.¹⁹⁹

23 Mr. Donihee, on behalf of the Board, was the only person to cross-examine the Corporation's
24 witnesses on the proposed T&Cs. His questions are addressed in following sections, as well as
25 the proposed changes to the Maximum Corporation Investment resulting from the Corporation's
26 response to 2001/03 Phase II GRA Board Directive 11.

27 **(a) Section 1.1 – Approval**

28 The proposed changes to section 1.1 fall under the housekeeping category of revisions.
29 References to the *PU Act* and the *Northwest Territories Power Corporation Act*²⁰⁰ ("*NTPC Act*")
30 and were both added to clarify the legal basis for the T&Cs. As noted above, subsection 63(3) of
31 the *PU Act* empowers the Board to approve the proposed amendments. Similarly, section 18 of
32 the *NTPC Act* empowers the Corporation to establish "...terms and conditions of service for the
33 supply of energy...". In that regard, Mr. Donihee questioned if the Board had authority under
34 the *NTPC Act* to approve the T&Cs.²⁰¹ The Corporation agrees that the Board's jurisdiction is
35 not conferred under the *NTPC Act*. The Corporation notes that this confusion could be avoided
36 with the following alternative wording "blacklined" against NTPC's current T&Cs:

¹⁹⁸ Tr. II, p. 95, lns. 7-17.

¹⁹⁹ Ex. 2, p. 7-1, lns. 6-15.

²⁰⁰ R.S.N.W.T. 1988, c. N-2.

²⁰¹ Tr. II, p. 145, ln. 20 to p. 146, ln. 13.

1 These Terms and Conditions of Service (hereinafter referred to as “Terms”) have
 2 been established by the Corporation in accordance with the *Northwest Territories*
 3 *Power Corporation Act*, R.S.N.W.T. 1988, c. N-2 and approved by the Public
 4 Utilities Board of the Northwest Territories (hereinafter referred to as the
 5 “Board”) pursuant to the *Public Utilities Act*, R.S.N.W.T. 1988, c. 24 (Supp.), and
 6 may not be changed without the approval of the Board.

7 **(b) Section 2.0 – Definitions of “Applicant”, “Customer”, “Government**
 8 **Customer” and “Industrial Customer”**

9 Sections 2.1 and 2.8 of the T&Cs provide definitions for “Applicant” and “Customer”,
 10 respectively. Mr. Donihee questioned whether the proposed changes to those definitions, which
 11 struck out the phrase “...firm, partnership, sole proprietorship, corporation, organization,
 12 association (including, without limitation, individual members of such association) or other
 13 entity”, were intended to eliminate entities that are not natural or legal persons. Mr. Courtoreille
 14 responded by confirming that “[o]ur intentions were to not -- not change the scope of that -- that
 15 provision or the intent of that provision. We would still expect a partnership or a corporation to
 16 be a customer.”²⁰² Mr. Courtoreille’s evidence is reflected in the new section 1.5 “Extended
 17 Meanings”, which reads as follows:

18 In the Terms, words importing single number only shall include the plural and
 19 vice versa, words importing the masculine gender shall include the feminine and
 20 neutral genders and vice versa and words importing a person shall include an
 21 individual, firm, partnership, association, trust, unincorporated organization,
 22 corporation Municipal Corporation, trustee or executor.²⁰³

23 Accordingly, reading sections 2.1 and 2.8 together with section 1.5 clearly indicates that entities
 24 that are not natural or legal persons are still covered by the definitions of “Applicant” and
 25 “Customer”. Mr. Courtoreille also clarified that the current definition of “Government
 26 Customer” was intended to identify customers that do not qualify for GNWT power subsidy
 27 programs.²⁰⁴

28 With regard to the proposed changes to the definition of “Industrial Customer” (section 2.21),
 29 Mr. Courtoreille explained the amendments in the following exchange with Mr. Donihee:

30 The intent of that revision was to recognize that industrial activities includes not
 31 only exploration and resource development, but also reclamation and cleanup
 32 after the project is completed. And in the old provision we had set a limit
 33 defining an industrial customer based on a thousand (1000) kilowatt consumption
 34 per month.

35 Recognizing that some of the reclamation activities and cleanup activities after
 36 the project is -- is completing -- completed or -- or finishing up, it is possible for

²⁰² Tr. II, p. 146, ln. 23 to p. 147, ln. 2.

²⁰³ Ex. 2, Appendix D,

²⁰⁴ Tr. II, p. 147, lns. 7-24.

1 the load to fall below that thousand (1000) kilowatt hour threshold, but it certainly
2 is still industrial in nature as it relates to mining.

3 MR. JOHN DONIHEE: I guess my -- yes, and I see the -- the change and I think
4 it does that, achieves what you've just indicated, but I guess the other -- the other
5 question I'm -- I'm having is whether or not you don't -- the -- the Corporation
6 doesn't contemplate anything other than a mine ever being categorized as an
7 industrial customer.

8 MR. TERENCE COURTOREILLE: I'm not sure if I'm understanding the
9 question. I -- I think our intentions are to classify any business with the primary
10 function of resource development -- development or mining, which includes or
11 not limited to construction operation, reclamation and the shutdown phases of
12 such businesses.²⁰⁵

13 The Corporation notes that any confusion regarding whether section 2.21 applies to the oil and
14 gas industry could be avoided with the following alternative wording "blacklined" against
15 NTPC's current T&Cs:

16 Means a classification referring to a business, the primary business of which is
17 oil, gas or mineral resource exploration, or development and extraction,
18 manufacturing or and mining, and which, including, but not limited to, the sole
19 opinion development, construction, operation, reclamation and shut down phases
20 of the Corporation acting reasonably, is anticipated to demand in excess of an
21 average of 1000 kW of energy per month such business.

22 **(c) Section 4.1 – Application for Service – General**

23 The Corporation is proposing to amend section 4.1 of the T&Cs by empowering the Corporation
24 to refuse service to an Applicant if a previous Customer living at the Applicant's premises has
25 existing arrears with the Corporation.²⁰⁶ Mr. Courtoireille explained that Corporation's rationale
26 for this change as having experienced an increasing number of incidents in which a customer
27 attempts to avoid payment arrears by having another member of their household apply for
28 service at the same residence. He also explained that the proposed amendment is consistent with
29 industry practice.²⁰⁷ In response to NUL.NTPC-35, the Corporation provided similar wording
30 from B.C. Hydro's Terms and Conditions of Service.²⁰⁸

31 The proposed amendment to section 4.1 is in the public interest and serves to protect the vast
32 majority of NTPC's customers by discouraging the few, albeit increasing number of customers
33 that have attempted to evade their payment arrears as discussed above. In the absence of this
34 provision, the continued trend of increasing arrears evasion will likely result in increased
35 collection and bad debt costs for the Corporation to the detriment of the remaining customers.

²⁰⁵ Tr. II, p. 148, ln. 8 to p. 149, ln. 9.

²⁰⁶ Ex. 2, p. 7-3, lns. 20-22.

²⁰⁷ Tr. II, p. 150, lns. 4-20.

²⁰⁸ Ex. 7.

1 The proposed changes were determined to be reasonable after having reviewed the (i) current
 2 corporate investment rates used by other utilities, (ii) NTPC's current costs to connect new
 3 customers and (iii) a net present value analysis of the costs and revenues associated with
 4 connecting new customers. Based on that review, the proposed corporate investment rates are
 5 comparable to other utilities, materially less in most sample cases than the costs for hooking up
 6 new customers and within levels that can be accommodated for an increase, respectively.²¹³

7 **8. Other Matters**

8 **(a) Standby Interconnection Guidelines**

9 Board Directive 8 from NTPC's 2001/03 Phase II GRA required to the Corporation to "...file the
 10 results of a study assessing the cost of providing standby service together with proposed standby
 11 service agreement including proposals for interconnection standards, subscription periods, exit
 12 fees and re-subscription fee..."²¹⁴ While the Corporation responded to that Direction in Chapter
 13 6 of the Application, based on comments from the Technical Workshop the Corporation has
 14 withdrawn its proposed standby rate design principles until the Phase II portion of this
 15 proceeding.²¹⁵

16 The Corporation is, however, still seeking approval from the Board of its Standby
 17 Interconnection Guidelines contained in Attachment 2 of Chapter 6 of the Application.²¹⁶ Those
 18 guidelines were prepared in conjunction with NUL, allow customers to better evaluate self-
 19 generation options and are required by the Corporation for safe and reliable service in the event
 20 that standby service is provided.

21 **(b) Stabilization Funds**

22 The Corporation's stabilization funds were established pursuant to the 1995/98 Phase I
 23 Negotiated Settlement. Parties to the 1995/98 Phase I Negotiated Settlement included the City of
 24 Yellowknife, Town of Inuvik, Miramar Con Mine Ltd. and NUL.

25 NTPC is proposing to continue and maintain all existing stabilization funds as active funds with
 26 updated variables to reflect approved 2006/07 and 2007/08 GRA values. Specifically, the
 27 respective fuel and water stabilization funds are proposed to be adjusted to incorporate the fuel
 28 prices, efficiencies and quantities of fuel, by community, for 2006/07 and 2007/08 as set out in
 29 Schedules 3.3.1 and 3.3.2.²¹⁷ Specific aspects of the stabilization fund operations that were
 30 examined during the hearing are discussed in more detail below.

31 **(i) Water Stabilization Fund**

32 NTPC currently maintains two water stabilization funds, one for the Snare-Yellowknife system
 33 and one for the Taltson system. NTPC is not proposing any changes to the mechanics of the

²¹³ Ex. 2, p. 6-21, ln. 15 to p. 6-24, ln. 11.

²¹⁴ Ex. 2, p. 6-6, lns. 2-5.

²¹⁵ Ex. 7, NTPC Cover Letter dated February 20, 2007; Ex. 13, Attachment A, pp. 3-4.

²¹⁶ Ex. 2.

²¹⁷ Ex. 13.

1 water stabilization funds, only to update the fuel prices and efficiencies to 2006/07 and 2007/08
2 values.

3 During the hearing, Mr. Bowman was asked by counsel for the Hydro Communities to confirm
4 that fuel expense amounts for the Snare-Yellowknife hydro system were netted off of the
5 Corporation's revenue requirement calculation as they would be charged to the water
6 stabilization funds. Mr. Bowman provided the following response:

7 That is correct, pursuant to the rules of the Snare/Yellowknife Water Stabilization
8 Fund as it now exists which the Corporation is not proposing in this GRA to
9 change. If the forecasts arise exactly as they are in the GRA and the Corporation
10 burns exactly that amount of fuel at that price, it will incur three hundred and
11 eighty-seven thousand dollars (\$387,000) worth of costs, but the operation of that
12 fund will ultimately pick up those dollars so that they do not need to be recovered
13 from ratepayers.

14 As a result, when you look at the revenue requirement in Chapter 3 you will see
15 that all production fuel costs in the hydro communities, both Snare/Yellowknife
16 and Taltson, are netted back out of the revenue requirement as not being required
17 to be paid by ratepayers through their firm rates because they will ultimately be
18 charged to the hydro fund pursuant to the rules in place.²¹⁸

19 Mr. Bowman was also asked if diesel expense incurred as part of the Snare Rapids Plant upgrade
20 was intended to be captured in the water stabilization fund. He confirmed that such diesel
21 expenses would indeed be charged to the water stabilization fund.

22 MR. PATRICK BOWMAN: Well, the rules of the fund do not include any terms
23 that provide for NTPC's discretion in terms of why diesel was run. The fund
24 says; I look at what the hydro generation level in rates is, based on normal water, I
25 look at the actual performance of the hydro plant. If it's lower than what was in
26 rates and as a result I had to burn diesel, that diesel flows through the fund.

27 That's all that the mathematics of the fund do, nothing more complicated. It does
28 not say -- it does not try to screen out or require any form of -- of over -- manual
29 overrides or discretion on NTPC's part as to what gets charged to the fund. Any
30 time the hydro system cannot perform to the level that's built into rates and as a
31 result diesel has to be run, the -- that diesel is charged to the fund. Any time the
32 hydro system over performs what is built into rates and as a result diesel
33 generation is saved, NTPC credits the fund with its diesel generation savings.

34 The math is -- is -- it's set out in one of the responses, there's an update on it and
35 it's relatively straightforward. In order to do what you're suggesting, Mr.
36 Marriott, is to -- is -- would be to somehow go through every month and say,
37 okay, but how much of that diesel was due to "A" versus "B" versus "C" and
38 somehow I have to decide and parcel it off and a result this diesel would be for a
39 different reason and this would be for a different reason.

²¹⁸ Tr. I, p. 189, ln. 23 to p. 190 ln. 16.

1 There's -- there's no -- no rules of that sort approved with this fund and so NTPC
2 doesn't have a lot of latitude or discretion to -- to go, sort of, making those up on
3 the fly.

4 MR. TOM MARRIOTT: So you would disagree that perhaps it would've been
5 more appropriate to charge the costs referred to in HC.NTPC-60B to capital and
6 the one in HC.NTPC-60C to the reserve for injuries and damages, perhaps?

7 MR. PATRICK BOWMAN: Clearly, Mr. Marriott, that would be the alt --
8 alternative. In the event these amounts weren't charged to the water stab. fund
9 they would be charged to other def -- deferred accounts just so -- or -- or to
10 capitalized amounts, so we're not talking about things that would hit NTPC's
11 bottom line in any event.

12 But in order to do that, like I said, one would have to start putting in place a -- a
13 discretionary aspect to -- to the diesel charge to the fund and that -- that hasn't
14 been in place to date. And -- and I -- I would say, one would want to be cautious
15 about putting something like that in place in terms of having to go back after the
16 fact and review the, you know.

17 Tho -- those -- those accounts that do have that need to have a discretionary
18 aspect and a gatekeeper and review after the fact become quite complicated; for
19 example, the reserve for injuries and damages we went through. I don't think the
20 Corporation would purpose adding this account to that list of -- of more difficult
21 accounts to review.²¹⁹

22 With respect to the long-term average output for the Bluefish Generating Station, the
23 Corporation has provided evidence that the revenue requirement in this application is not
24 sensitive to the assumed capability of the Bluefish plant (42.5 GW.h as proposed by NTPC
25 versus some higher value), as the system currently has surplus hydro. During the hearing,
26 counsel for the Hydro Communities asked whether the long-term average generation figure for
27 Bluefish should be updated and had the following exchange with Mr. Bowman:

28 MR. TOM MARRIOTT: I guess what we're struggling with is that it was our
29 understanding that the Bluefish application was based on an economic analysis
30 that took into account the 42.5 gigawatt hours of -- of hydro generation from
31 Bluefish, plus what could be achieved with the upgrades.

32 Wasn't the economic analysis based on that?

33 MR. PATRICK BOWMAN: Mr. Marriott, you're correct. The Bluefish in the
34 economics was based on that, it is still based on that and updated economics as
35 provided in BR-9 that still reflects that once the system load grows to a point
36 where you need 47.3 gigawatt hours of Bluefish, Bluefish will be able to provide
37 it.

²¹⁹ Tr. I, p. 194, ln. 24 to p. 197, ln. 8.

1 The issue we're struggling with today is given additional information about the
2 Bluefish plant and given the capital projects that have been undertaken and
3 prioritized to date, are we able to say 47.3 is the right new number for Bluefish
4 and -- and I -- what -- what the Corporation has put on the record is that they can't
5 say that.

6 They can't say that in part because of the types of analysis I was talking about that
7 they would want to do in a more detail before they adopt that number and they
8 also can't say that because the capital projects that have been undertaken to date,
9 and this is discussed more in one (1) of the IR's and I -- I don't recall off the top
10 of my head which one it is immediately, but because there's surplus hydro on the
11 system to date, the types of capital projects that have been prioritized are not
12 those that increase the output because there's no economic value to increased
13 output to date.

14 Those are the types of capital projects that will be done later in the analysis and
15 are included in the economics and are still included in the economics for future
16 years. They have just not been the Corporation's priority at -- at this time because
17 it has no impact on the cost of the system.²²⁰

18 Counsel for the Hydro Communities also asked whether the Corporation would undertake to
19 adjust the Bluefish output for the purposes of the Water Stabilization Fund following the
20 refurbishment of the Bluefish intake, to which Mr. Bowman replied:

21 Mr. Marriott, as was noted in the Bluefish application and is still true today, the
22 Corporation's intention is to do its best to reflect the long-term average output of
23 the plants at the time when it can come up with a better, more meaningful
24 number.

25 The trick you run up against when you're dealing with the long-term average
26 output of hydro plants is it's a fairly complicated system modeling exercise. It's --
27 it's quite expensive and you have to model the system as a whole, and you have to
28 model it against an underlying load that requires you to use that water, that
29 requires that much hydro, and then you have to run through that model all of the
30 different flow conditions that might arise, from drought to flood and figure out
31 how much spillage there might be and figure out how you might dispatch the
32 plants.

33 NTPC doesn't have a system that has a load at that level today. So, even if --
34 even if they did retain some experts to try to model the long-term average water
35 flow of the system, unless someone sort of dreamed up a hypothetical load that
36 could actually use that much water, you can't even meaningfully do that analysis.

37 In any event, there's no diesel forecast in this -- in this rate application, so for --
38 for the Snare/Yellowknife system that would flow through to rates. It would all
39 flow through to the Water Stabilization Fund, so it would have no impact on the
40 revenue requirement we're talking about today.

²²⁰ Tr. I, p. 86, ln. 24 to p. 88, ln. 11.

1 But certainly, the Corporation is not -- not resisting the thought that -- that it will
 2 need to update its long-term hydrology number at the time when long-term
 3 hydrology becomes a material factor in its revenue requirement.²²¹

4 Consequently, there is no need to revisit the Bluefish long-term average generation figure used in
 5 the Snare-Yellowknife hydro stabilization fund (and the test years' fuel expense forecast) as any
 6 changes would not have any impact on the test years' Revenue Requirements. The Corporation
 7 will revisit the long-term average output of Bluefish when it becomes a material consideration in
 8 the development of the Corporation's Revenue Requirement.

9 **(ii) Fuel Stabilization Funds**

10 NTPC maintains five fuel stabilization funds, one for each of the Snare-Yellowknife system, the
 11 Taltson system, Inuvik, Norman Wells and the remaining diesel communities. NTPC is
 12 proposing only to update the fuel prices, fuel efficiencies and generation volumes (in the case of
 13 the dual fuel Inuvik and Norman Wells funds) to the test year values and is not proposing
 14 changes to the mechanics of these funds.

15 With respect to the revisions to the Norman Wells Fuel Stabilization Fund discussed in
 16 BR.NTPC-19 b), the Agreement with the Town of Norman Wells did not result in NTPC
 17 incurring material additional fuel expense and the Agreement has now expired. Therefore NTPC
 18 does not require any revisions to the Norman Wells Fuel Stabilization Fund.

19 With respect to the fuel efficiencies used in the calculation of the funds, the TGC provided
 20 evidence suggesting that rather than using the GRA approved efficiencies, as the Corporation has
 21 done in the past and proposes to continue, the efficiencies should be true-up at the end of each
 22 year using the actual fuel efficiencies for the most recent year.²²²

23 The Corporation noted that while the change suggested by the TGC would remove the
 24 Corporation's risk related to fuel efficiency on the portion of the fuel price that is different from
 25 the GRA forecast included in base rates, NTPC would still be at risk for efficiency for the GRA
 26 forecast price of fuel. Therefore, the TGC proposal would have minimal consequences.²²³

27 With respect to the whether the Diesel Community Fuel Stabilization Fund should include all the
 28 diesel communities or be in effect a separate fund for each community, Mr. Merani
 29 recommended that:

30 ...the true-up should be in reference to the community's own diesel costs. This
 31 will involve the calculation of a community-specific rate rider, no different than
 32 the community-specific base rates currently in place. This would also then be
 33 consistent with the Board-approved community-based approach to rate-making.²²⁴

²²¹ Tr. I, p. 85, ln. 12 to p. 86, ln. 20. See also Tr. I, p. 200, ln. 6 to p. 201, ln. 13.

²²² Ex. 10, p. 11, ln. 22 to p. 12, ln. 13.

²²³ Ex. 12, NTPC Rebuttal Evidence, p. 14, lns. 5-28.

²²⁴ Ex.10, p.11, lns. 16-19.

1 Mr. Merani apparently arrives at this recommendation based on the misapprehension that the
 2 mechanics of the fund confers upon some communities the permanent status of being subsidy
 3 providers.²²⁵ Mr. Merani's understanding of the fund mechanics is incorrect. There is no basis
 4 in evidence to conclude that some communities are perpetually subsidizing others in the Diesel
 5 Fuel Stabilization Fund.²²⁶ Rather, there is only one diesel Fuel Stabilization Fund established
 6 instead of separate funds for each community because:

7 ...in the 1995/98 GRA Negotiated Settlement, NTPC and customers agreed to this
 8 format for a number of reasons. First was that there was no reason to expect fuel
 9 price variation and cost pressures to differ materially among the diesel
 10 communities, so there would be no expectation of better cost tracking were one to
 11 use a community-specific rider. Second was that a single fund was practical to
 12 administer. Third was a clear customer desire to have the rider be pooled to
 13 secure stability and "insurance" type benefits. As a result, the current single rider
 14 across all NTPC diesel communities is a significantly better approach than having
 15 the rider established for each community.²²⁷

16 Mr. Merani's recommendation for individual community-based fuel stabilization funds is based
 17 on a flawed understanding of the mechanics of the fund, would be difficult and costly to
 18 administer without material cost tracking benefits, and is clearly contrary to the spirit and intent
 19 of the fund at the time it was established. The Board should disregard Mr. Merani's
 20 recommendation.

21 (c) Accounting Provisions

22 There are a number of new provisions in Canadian Generally Accepted Accounting Principles
 23 ("GAAP") that are in effect since the 2001/03 GRA or are emerging and may be in effect over
 24 the next few months or years. NTPC is very familiar with those developments closely following
 25 them, including by actively participating with Canadian Electricity Association's finance
 26 committee and consulting with other utilities.²²⁸ In order to be proactive in addressing the
 27 implications for rate regulation, the Corporation is seeking approval and confirmation from the
 28 Board to continue to account for various regulatory assets and liabilities consistent with past
 29 practice and Board approvals.

30 The first of these areas is with respect to deferral accounts. NTPC has received the Board's
 31 approval in prior applications for the deferred treatment of the following deferral accounts/costs:

- 32 • rate stabilization funds;²²⁹
- 33 • overhauls;²³⁰

²²⁵ Ex. 10, p. 11, lns. 4-14.

²²⁶ For example, see Ex. 12, NTPC's Rebuttal Evidence, p. 12, ln. 14 to p. 13, ln. 14.

²²⁷ Ex. 7, BR.NTPC-18 (e).

²²⁸ Tr. II, p. 85, ln. 14 to p. 86, ln. 7.

²²⁹ See PUB Decision 1-97 at 26-28 & 31 and s. 4 of the Negotiated Settlement Agreement dated November 13, 1996; PUB Decision 1-2002 at 24.

- 1 • regulatory hearing costs;²³¹
- 2 • financing costs;²³²
- 3 • injuries and damages;²³³
- 4 • Snare Cascades deferral account;²³⁴
- 5 • employee future benefits;²³⁵
- 6 • deferred revenues related to customer contributions to aid in the acquisition of property, plant
7 and equipment;²³⁶ and
- 8 • other regulated assets, comprised of capital studies waiting for capital asset construction or
9 determined not feasible.

10 The continued treatment of these deferral accounts in accordance with prior Board approvals
11 (subject to updated variables) will uphold the desired outcome for which they were first
12 established by smoothing the rate impact to customers and allowing the Corporation the
13 opportunity to recover its prudently incurred costs.

14 NTPC also seeks Board approval for a new deferral account for water licensing and for the
15 general treatment of deferring future costs over a period of time, where costs incurred in one year
16 have a longer term benefit to customers and are significant in magnitude (eg. job evaluation).²³⁷
17 The Corporation believes that this position is consistent with Decision 1-97 where the Board
18 applied the test of whether the Snare Cascades “project was needed over the long term and has
19 been occurred at prudent cost. Further, the Board is of the view that the phase in is reasonable
20 and fairly balances the needs of NWTPC and the ratepayers in the Snare Yellowknife System.”

21 A second area that is impacted by new accounting guidelines is Asset Retirement Obligations. In
22 the past NTPC has recorded a provision for the future removal of assets and site clean up costs
23 for the majority of its assets. This treatment was supported by GAAP, and approved by the PUB
24 as part of the Corporation’s periodic depreciation reviews. Changes to GAAP in the last few
25 years now require the recording of a liability only in cases where there is a “legal obligation” for
26 the asset disposal or site clean-up and to reverse to equity any other retirement obligations
27 liabilities.

²³⁰ PUB Decision 1-2002 at 11 & 20 and s. 17 of the Negotiated Settlement dated November 20, 2001.

²³¹ PUB Decision 1-2002 at 20 and s. 9 of the Negotiated Settlement dated November 20, 2001.

²³² PUB Decision 1-220 at 20 and Negotiated Settlement dated November 20, 2001, Table 3.2.2, Ins. 18-23 & 33.

²³³ PUB Decision 1-2002 at 9 and 10.

²³⁴ Decision 1-97 at 6-9 and s. 3 of the Negotiated Settlement Agreement dated November 13, 1996.

²³⁵ PUB Decision 1-2002 at 20 and s. 11 of the Negotiated Settlement dated November 20, 2001.

²³⁶ PUB Decision 2-94 at 89.

²³⁷ Tr. I, pp. 174-175; Ex. 2, p. 3-22, Ins. 7-9.

1 The Corporation requests Board approval to continue with past practice of maintaining a liability
 2 for the Future Removal for Site Restoration for the removal and clean-up of all its assets
 3 regardless of legal obligations or otherwise which will maintain fair intergenerational allocation
 4 of costs (that customers are paying for the cost of the assets they are using, including costs of
 5 disposing of these assets and restoring the facility sites) as well as smoother rates.²³⁸ To prevent
 6 double counting of the liability should an Asset Retirement Obligation (“ARO”) arise in
 7 accordance with GAAP as a result of legislation or contractual obligation, NTPC proposes that
 8 the reserve balance would be reduced by an amount required to set up the ARO liability.

9 The third area of accounting where NTPC is seeking Board approval is with respect to
 10 accounting for Financial Instruments. For the purposes of establishing a revenue requirement,
 11 NTPC maintains that only realized gains and losses should be reflected in the Corporation’s debt
 12 and equity calculation. The new accounting guidelines require that certain Financial Instruments
 13 be valued at market (including both realized and unrealized gains and losses) which has potential
 14 to cause wide fluctuations in the value of those assets and in the calculation of regulated debt and
 15 equity at any point in time. Inclusion of unrealized gains and losses is an accounting valuation
 16 that does not translate well for rate setting purposes. It will not only cause significant variation
 17 in rates from year to year but will also add complexity to the development and testing of the debt
 18 and equity forecasts which is likely to add cost to the regulatory process. Such a result is not in
 19 the interest of NTPC or its customers.

20 NTPC’s long term practice of amortizing financing costs associated with the acquisition of long
 21 term debt aids ratepayers by ensuring fair intergenerational allocation of costs related to long
 22 term financing as well as smoother rates and a stable progression towards debt retirement. The
 23 Board has approved the deferral of long term debt financing costs for the long term debt acquired
 24 prior to December 2005. NTPC seeks the Board’s approval for continuation of this accounting
 25 approach; specifically, deferring the financing costs of all long term debt acquired after
 26 December 2005.

27 **(d) Inter-Affiliate Transactions**

28 The question of inter-affiliate transactions was raised by the TGC in the Prepared Testimony of
 29 Mr. Azad Merani on Phase I Matters. In that evidence, Mr. Merani recommended that NTPC
 30 file, among other things, a code of conduct modeled after the ATCO Group code of conduct no
 31 later than NTPC’s next GRA.²³⁹ Mr. Merani subsequently clarified that the intention behind his
 32 recommendation was simply “transparency”, which he suggested can only be addressed through
 33 the codification of principles in a document that has been approved by the Board – he was not
 34 suggesting that NTPC was doing anything wrong in how it addressed inter-affiliate
 35 transactions²⁴⁰ nor did he suggest that NTPC’s “checks and balances” were insufficient.

36 Accordingly, the issue for this hearing is not whether the ATCO Group code of conduct should
 37 be adopted for the Corporation, which Mr. Merani candidly acknowledges that it should not.²⁴¹
 38 Rather, the issue is whether the checks and balances identified by the Corporation and tested in

²³⁸ PUB Decision 2-94 at 59; PUB Decision 1-2002 at 6-9.

²³⁹ Ex. 10, p. 5, ln. 25 to p. 6, ln. 2.

²⁴⁰ Tr. III, p. 28, ln. 14 to p. 29, ln. 9.

²⁴¹ Tr. III, p. 14, lns. 3 to 17; Tr. III, p. 29, ln. 18 to p. 30, ln. 2.

1 this hearing provide sufficient transparency to satisfy the Board that the costs of yet another
 2 proceeding should be avoided – costs that the TGC suggests should also be borne by the Hydro
 3 Communities.²⁴²

4 The Corporation clearly recognizes the importance of having appropriate and rigorous “checks
 5 and balances” in place to govern inter-affiliate transactions and prevent cross-subsidization
 6 among affiliates. As noted by Ms. Goucher, the Corporation took “...great pains in identifying
 7 any costs that were related to our non-regulated operations. ... We reviewed all of our activities
 8 related to the non-regulated subsidiary and operations and we did not include those as costs for
 9 the regulated customer in this rate application.”²⁴³

10 The Corporation provided the following detailed description of its inter-affiliate cost tracking
 11 procedures:

12 For cost tracking purposes, NTPC maintains different plant numbers for each of
 13 its non-regulated subsidiaries to identify transactions related to non-regulated
 14 companies. It also maintains different plant numbers for each community and
 15 head office to track the regulated operations of the Corporation. For capital assets
 16 or long term projects undertaken by the non-regulated subsidiaries, specific
 17 projects accounts are set up to separate these costs from regulated operations, as
 18 well as non-regulated operational expenses.

19 There are two ways in which costs are allocated to non-regulated operations:

- 20 1. Direct charge – time and supplies are directly coded to the non-regulated
 21 plants for those costs that are readily identifiable as non-regulated
 22 transactions. This would include such costs as:
 - 23 a. direct employees whose salaries are separated from the regulated
 24 operations and directly charged to the non-regulated operations via
 25 timesheets;
 - 26 b. time spent to build assets or perform operational on a periodic basis for the
 27 non-regulated operations – these costs would be charged through
 28 timesheets;
 - 29 c. interest expenses on debt held by the non-regulated operations;
 - 30 d. daily operational costs (ie. rent, office supplies, hiring costs, advertising,
 31 etc.) for non-regulated operations are directly charged to the appropriate
 32 plant through service agreements or purchase orders; and
 - 33 e. travel is itemized and coded using travel claims.
- 34 2. Overhead allocations – for costs that are incurred in small increments or are
 35 not readily identifiable as non-regulated transactions, the Corporation applies

²⁴² Tr. III, p. 35, ln. 15 to p. 36, ln. 1.

²⁴³ Tr. I, p. 228, lns. 14-24.

1 an overhead allocation from regulated operations to non-regulated operations.
2 This overhead allocation is reviewed on an annual basis to ensure the rates are
3 applicable for the non-regulated activity expected each year. This would
4 include such costs as time for financial reporting, purchasing and IT spent on
5 producing financial statements, purchasing supplies and maintaining
6 computers for the non-regulated operations.

7 Shared services transactions are tracked throughout the year. Financial statements
8 are produced annually at which time the accounts are reconciled and shared
9 services transactions involving those subsidiaries are checked to ensure they are
10 correct.²⁴⁴

11 Ms. Goucher also provided the following description:

12 The first check and -- and in terms of the allocation of costs between the regulated
13 and non-regulated parts of NTPC is through the budget process and we go
14 through three (3) cycles of reiteration and part of that budget process is to identify
15 the direct costs associated with the subsidiary NTEC 03 Limited.

16 In addition, part of that budget process is to identify, based on a forward forecast
17 estimate, the amount of time that various positions within the Corporation might
18 spend in the upcoming year based on a forecast level of activity providing
19 services to the subsidiary.

20 At the same time we identify, to the extent possible, whether or not there might be
21 any costs associated with, for example, the hiring of personnel.

22 However, that happens very rarely. They have two (2) persons right now in the
23 organization and they have been hired for some time. The need for computer
24 services and that is also not variable. Now that they are up and running... there's
25 not significant variances in that.

26 Any payroll services or benefits services, again, the two (2) persons who are in
27 the Energy Corp. subsidiary have -- I'm going to say, fairly consistent activity in
28 that regard and -- and we are able to predict, with some accuracy, what portion of
29 the regulated businesses is serving them.

30 The biggest one (1) that I mentioned is what time perhaps senior managers and
31 particularly -- in particular, the CEO or CFO, or any engineering services that
32 might required in the upcoming year. And we identify those and then we go
33 through three (3) iterations to ensure that we have been accurate in terms of
34 allocating the costs.

35 As I said, the emphasis on -- is on, to the extent possible, identifying the direct
36 costs associated with these subsidiaries. For example, the corporate secretary
37 automatically has half of her time charged to the non-regulated subsidiary, as do
38 the two (2) persons who work in there.

²⁴⁴ Ex. 12, NTPC Rebuttal Evidence, p. 5, ln. 29 to p. 6, ln. 21.

1 So -- then throughout the year on a quarterly basis, we prepare -- we prepare a
 2 variance analysis and report to our Board of Directors. And in addition, at year
 3 end we go through an audit process and the subsidiaries are part of the
 4 consolidated financial statements that the Corporation produces every year and
 5 are -- and those statements are audited by the Auditor General of Canada, so
 6 that's the process that we go through.²⁴⁵

7 The above checks and balances are similar in scope and detail to the checks and balances
 8 followed by other Crown owned electric utilities, specifically Newfoundland and Labrador
 9 Hydro, and Manitoba Hydro.²⁴⁶

10 Consequently, the question of transparency has been addressed in this proceeding. By approving
 11 the above checks and balances and requiring the Corporation to continue to apply them, the
 12 Board can be assured that inter-affiliate cross-subsidization will continue to be avoided.

13 **(e) Generation Using Sources Other than Diesel**

14 The Corporation clearly recognizes the challenges associated with providing electric power in
 15 Arctic communities. As noted in Ms. Goucher's opening statement:

16 Diesel fuel price increases have been experienced as high as 75 percent in some
 17 communities. These are causing major rate pressures in communities that rely on
 18 diesel for their generation.

19 And while we've worked hard to minimize this impact to the extent possible, in
 20 many of those communities there are simply no practical alternatives to diesel
 21 generation at this time. And this challenge is also faced by utilities that serve
 22 other remote parts of Canada.²⁴⁷

23 The Corporation's efforts to mitigate diesel costs are summarized in section 2(b) above and not
 24 repeated here. The Corporation has also been very active in pursuing government funding for
 25 alternative energy projects over the years and will continue to do so.²⁴⁸ However, as discussed in
 26 NTPC's Rebuttal Evidence:

27 To the extent that Mr. Merani's proposition would require NTPC to aggressively
 28 pursue alternative energy funding beyond its current efforts and report quarterly
 29 on its efforts to the PUB, NTPC does not have sufficient resources to fulfill this
 30 request. NTPC maintains that the current level of effort to acquire third party
 31 funding either directly or through assisting communities to obtain funding is
 32 appropriate and that quarterly reporting on these efforts would be done at the
 33 expense of using resources to successfully acquire funding. If Customers in the
 34 diesel communities determine that this is a high priority, NTPC would be willing
 35 to amend its 2006/08 rate application to include a position to aggressively and

²⁴⁵ Tr. I, p. 245, ln. 10 to p. 247, ln. 9.

²⁴⁶ Ex. 12, NTPC Rebuttal Evidence, p.6, ln. 39 to p. 8 ln. 13.

²⁴⁷ Tr. I, p. 41, lns. 13-22.

²⁴⁸ Ex. 12, NTPC Rebuttal Evidence, Appendix A.

1 proactively pursue alternative energy funding and make reports to the Board on a
2 full time basis.²⁴⁹

3 Absent consensus from NTPC's customers that additional resources should be applied to seeking
4 out and reporting on third party funding for alternative energy projects, the Corporation submits
5 that its current program is reasonable and nothing further is required from the Board.

6 **(f) Fuel Efficiency – Town of Inuvik**

7 Fuel efficiency for the Town of Inuvik is forecast in the Application at 3.399 kW.h/m³ for both
8 test years.²⁵⁰ As discussed in section 4(b) above, that forecast is based on a weighted average of
9 the past three years' actual plant efficiencies and no adjustment was made for the third Inuvik
10 gas engine installed in 2006/07.

11 Mr. Merani has suggested that "...there is no doubt the addition of the third engine in Inuvik
12 should result in an increase in the gas efficiency. This review of changes in efficiency associated
13 with a new plant or engine suggests an efficiency increase of at least 5% is appropriate."²⁵¹

14 The evidence does not support Mr. Marani's suggestion. The third Inuvik gas engine is not
15 likely to have a better fuel efficiency than the existing gas gensets that are only 4 to 5 years
16 older.²⁵² Further, manufacturer's fuel efficiency ratings are not useful for GRA forecasts. As
17 Mr. Kerr noted, manufacturer's ratings "...are based on one (1) hour of continuous operation at
18 those loads, but it does not take into consideration any fuel consumed to warm up or cool down
19 the engine."²⁵³ Clearly the manufacturer's fuel efficiency ratings do not reflect real world
20 conditions, which a GRA forecast is intended to mirror, and should not be applied in this case.

21 Consequently, a 3.399 kW.h/m³ forecast fuel efficiency for the Town of Inuvik is reasonable and
22 the Board should disregard Mr. Merani's suggestion.

23 **(g) Behchoko Submission**

24 As noted in section 1 above, the Community of Behchoko filed a written submission dated May
25 22, 2007. That submission was filed by Mr. Telmo dos Santos of VISION Consulting and it
26 appears that it does not take into account any of the materials filed in this proceeding other than
27 the Application, such as the revised revenue requirements set out in the Corporation's May 16,
28 2007 re-filing.²⁵⁴ The Corporation's reply to the arguments contained in the submission is set
29 out below. To the extent that the Corporation does not expressly reply to a specific claim, it
30 should not be assumed that the Corporation agrees with that claim. Where appropriate, reference
31 is made to the applicable section above, rather than repeating the Corporation's argument.

²⁴⁹ Ex. 12, NTPC Rebuttal Evidence, p. 10, ln. 40 to p. 11, ln. 3.

²⁵⁰ Ex. 2, Schedule 2.1, ln. 33; Ex. 7, BR.NTPC-6a, Table 6a.

²⁵¹ Ex. 10, p. 14, lns. 4-7.

²⁵² Ex. 12, NTPC Rebuttal Evidence, p. 15, ln. 30-35.

²⁵³ Tr. II, p. 20, lns. 19-22; see also Ex. 12, p. 15, lns. 4-12.

²⁵⁴ Ex. 13, p. 2, Table 1.

1 Mr. dos Santos suggests that the Corporation's proposed revenue requirements are 25.71% and
 2 26.54% higher than the 2001/03 GRA for 2006/07 for 2007/08, respectively, and that the
 3 revenue requirement Corporation should be capped at 12.16% "actual inflation".²⁵⁵ Mr. dos
 4 Santos' calculations do not distinguish between the impact of incorporating costs currently
 5 recovered by rate riders and core impacts related to other aspects of NTPC's revenues and costs.
 6 As noted by Ms. Goucher, "...approximately one-third of the total 2006/'07 revenue requirement
 7 increase is attributable to incorporating previously approved rate riders."²⁵⁶ Once the impact of
 8 rider adjustments is taken into account, the "core" increase to rates in 2006/07 would be
 9 approximately 15.01% or 3.56% per annum over the 2002/03 test year.²⁵⁷

10 Mr. dos Santos questions the at-risk compensation awarded by the Corporation.²⁵⁸ NTPC's reply
 11 to that concern is set out in section 4(a)(i) above.

12 Mr. dos Santos suggests that "...[t]here should therefore be a separate calculation for head office
 13 O & M costs and other non head office O & M costs to ensure that the overall Operations and
 14 Maintenance costs between head office and non head office are similar."²⁵⁹ The Corporation has
 15 provided that information in this proceeding.²⁶⁰

16 Mr. dos Santos questions the amounts proposed to be added to rate base for Bluefish Generating
 17 Station and the Fort McPherson Power Plant.²⁶¹ The reply to those concerns is set out in sections
 18 6(a)(i) and (ii) above, respectively.

19 Mr. dos Santos suggests that the Board should "...commission one [a depreciation study] prior to
 20 determining the current GRA or as soon as is practicable."²⁶² For the reasons discussed in
 21 section 4(c) above, that suggestion should be disregarded.

22 With respect to rate of return, Mr. dos Santos suggests that in fixing a fair return the Board have
 23 regard to the fact that the Corporation is owned by the GNWT and its "profit" should be adjusted
 24 to help ameliorate high rates of welfare, poverty and homelessness in the NWT.²⁶³ In effect, Mr.
 25 dos Santos is requesting the Board to abandoned the stand-alone principal of ratemaking. Both
 26 the Corporation's and even the Hydro Communities rate of return experts would advise against
 27 that position.²⁶⁴ Section 4(f)(iv) above discusses why the stand-alone principle should apply.

²⁵⁵ Behchoko Submission, p. 5, Tables 1.1 and 1.2

²⁵⁶ Tr. I, p. 38, lns. 1-3. See also Ex. 2, Executive Summary, p. 5.

²⁵⁷ Ex. 2, p. 4-6, lns. 3-5. It should be noted that these figures have not been updated to reflect NTPC's revised revenue requirement set out in its May 16, 2007 Re-filing (Ex. 13).

²⁵⁸ Behchoko Submission, p. 6.

²⁵⁹ Behchoko Submission, p. 7.

²⁶⁰ Ex. 3, SM-5; Ex. 4, Undertaking # 13.

²⁶¹ Behchoko Submission, p. 7.

²⁶² Behchoko Submission, p. 8.

²⁶³ Behchoko Submission, p. 8.

²⁶⁴ Ex. 2, Appendix B, p. 2, lns. 48-75; Ex. 8, p. 5.

1 Mr. dos Santos also implicitly argues that the Corporation should be used by the GNWT as an
 2 instrument to implement public policy. Regarding public policy, the Board, in considering a
 3 proposal for the affordability of electric power and rate zone options, has held:

4 As a final matter, the Board is deeply concerned about the affordability of power
 5 rates in the NWT. The Board fully recognizes the potential impact in the diesel
 6 communities of having rates which reflect costs.

7 *The Board believes it is the responsibility of the GNWT to set policies with respect*
 8 *to matters of social engineering.* The Board appreciates that it must consider the
 9 broad public interest in formulating its Decisions, however, the Board does not
 10 believe it should decide the extent to which one group of ratepayers should or
 11 should not subsidize the cost of power consumed by another group of
 12 ratepayers.²⁶⁵ [emphasis added]

13 The Board should not be persuaded by Mr. dos Santos argument as it contravenes the stand-alone
 14 principal and is contrary to past Board precedent.

15 **9. Conclusion**

16 This Written Argument sets out the reasons and support for the Corporation's 2006/08 Phase I
 17 GRA. The costs, revenues at existing rates and resulting shortfalls are based on prudent and
 18 reasonable forecasts of NTPC's expected operations over the 2006/07 and 2007/08 test years. In
 19 that regard, it is notable that the only evidence adduced by interveners to rebut the Corporation's
 20 forecasts has been that of Drs. Kryznowski and Roberts, on behalf of the Hydro Communities, in
 21 respect of rate of return matters and Mr. Merani, on behalf of the TGC, respecting the diesel Fuel
 22 Stabilization Fund and the fuel efficiency rate for Inuvik. The Corporation has fully answered
 23 the concerns raised by those witnesses. The Corporation has also proposed reasonable
 24 amendments to its T&Cs and new Standby Interconnection Guidelines required by the
 25 Corporation for safe and reliable service. The Corporation is not proposing any changes to its
 26 stabilization funds, except to incorporate updated fuel prices, efficiencies and quantities of fuel,
 27 by community, for the test years.

28 As noted by Ms. Goucher in her opening statement:

29 ...the Corporation is currently operating under interim refundable rates pursuant
 30 to Board Decision 2/2007. ...

31 Upon receipt of a Board decision on this application, the Corporation will be in a
 32 position to re- file its test year revenue requirements and rate-based balances with
 33 final rate riders by community.

34 In conclusion, the Corporation has put forth a Phase I application based on a
 35 reasonable and realistic cost and revenue forecast. Approval of the requested
 36 revenue requirements and rate-based balances will allow the Corporation to
 37 continue to provide safe and reliable service while at the same time earning a fair
 38 rate or return.

²⁶⁵ PUB Decision 5-95 at 57.

1 The Corporation requires a Board decision on this application in order to finalize
2 its 2006/2007 financial statements. A timely decision from the Board will assist
3 in that regard.²⁶⁶

4 Accordingly, we respectfully requests that the Board approve the Corporation's 2006/08 Phase I
5 GRA and grant the requested relief set out in section 1(a) above.

6 **ALL OF WHICH** is respectfully submitted this 18th day of June, 2007.

7
8 Borden Ladner Gervais LLP,
9 counsel for the Northwest Territories Power
10 Corporation
11

12
13
14 "Stephen Lee"
15 Per: Stephen C. Lee

16
17
18
19 "Hugh Williamson"
20 Per: Hugh D. Williamson, Q.C.

²⁶⁶ Tr. I, p. 47, ln. 12 to p. 48, ln. 9.