

**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 II GRA and Rate  
Finalization Application;

AND IN THE MATTER OF a Review of the Northwest Territories  
Power Corporation's Code of Conduct and Responses to Directives  
49 and 50 from Decision 13-2007.

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

**October 14, 2008**

## Table of Contents

<b>1. Introduction.....</b>	<b>1</b>
(a) Requested Relief.....	2
<b>2. Background .....</b>	<b>4</b>
(a) <i>Public Utilities Act</i> .....	4
(b) The Northwest Territories Power Corporation .....	5
<b>3. Interim Rates for 2006/07 and All Previous Periods .....</b>	<b>6</b>
<b>4. Consolidation of the 2006/07 and 07/08 GRA Shortfalls.....</b>	<b>6</b>
<b>5. Adjustments to 2007/08 base rates, stabilization fund riders and shortfall riders .....</b>	<b>7</b>
<b>6. Interest Rate Applicable Shortfall Balances.....</b>	<b>13</b>
<b>7. Standardized Dates for Stabilization Fund Applications.....</b>	<b>14</b>
<b>8. Stand-by Rate proposal.....</b>	<b>18</b>
<b>9. Terms and Conditions of Service.....</b>	<b>20</b>
<b>10. Other Matters.....</b>	<b>21</b>
(a) Time-of-Use Rates .....	21
(b) Potential Directive to Achieve Certain Revenue to Cost Ratios in the Next Phase 2 GRA .....	23
<b>11. Code of Conduct Review .....</b>	<b>24</b>
(a) Purpose of Code of Conduct.....	24
(b) Development of Inter-Affiliate Transaction Policy and Code of Conduct .....	25
(c) Northwest Territories Hydro Corporation Act.....	26
(d) Taltson Expansion Advantages and Disadvantages to Regulated Customers .....	26
(e) Affiliate Transactions and Cost Tracking .....	27
(f) Responsibilities of Board of Directors.....	28

1     **1.     Introduction**

2     By letter dated November 30, 2007, the Corporation filed its response to Directive 50 of Board  
3     Decision 13-2007. By letter dated January 31, 2008, the Corporation filed its response to  
4     Directive 49, from Board Decision 13-2007<sup>1</sup>. Directive 49 ordered NTPC to file a formalized  
5     inter-affiliate Code of Conduct with the Board identifying principles related to transactions with  
6     NTPC’s parent; NT Hydro, affiliates, and non-regulated companies. Directive 50 ordered NTPC  
7     to explain how the interests of regulated customers will be protected in the interactions between  
8     NTPC and NT Hydro, with particular regard to new generation and sales opportunities.<sup>2</sup>

9  
10    On August 15, 2008, the Northwest Territories Power Corporation (the “Corporation” or  
11    “NTPC”) filed with the Northwest Territories Public Utilities Board (the “Board” or “PUB”) its  
12    2006/07 and 2007/08 Phase II General Rate Application and Rate Finalization Application.

13  
14    By letter dated August 19, 2008, the Board noted its intent to combine its review of the Phase 2  
15    GRA with the review of NTPC’s inter-affiliate code of conduct and conflict of interest guidelines  
16    (the responses to Directives 49 and 50 of Decision 13-2007). The Board’s letter also noted that  
17    since NTPC is not proposing changes to the cost of service methodology, the Board questioned  
18    the need for the full typical Phase 2 review process which includes an oral public hearing. The  
19    Board’s letter requested comments from NTPC and intervenors as to the required extent of the  
20    review process, including the need for an oral public hearing.

21  
22    Comments were received by letter from the City of Yellowknife and the Towns of Hay River and  
23    Fort Smith (collectively the “Hydro Communities” or “HC”) and the communities of Fort Liard,  
24    Fort Simpson and Inuvik (collectively the “Thermal Generation Communities” or “TGC”) on  
25    August 26, 2008.

26  
27    The HC letter stated “(b)ased on a preliminary review of the Phase 2 GRA, we tend to agree with  
28    NTPC that there is little latitude to do much rate rebalancing between rate classes and  
29    communities at this time. A full review of a cost of service study would be costly and may be  
30    somewhat academic as to how it would or could be reflected in rate design at this time.”<sup>3</sup> and  
31    further, “(w)e are prepared to work towards the more expedited schedule”.<sup>4</sup>

32  
33    The TGC letter stated that “(b)ased on a high level review of the Phase 2 GRA, the TGC agree  
34    with NTPC a “simplified approach” to Phase 2 GRA will result in reduced regulatory and

---

<sup>1</sup> Judith Goucher, January 31, 2008, letter from NTPC to Joe Acorn, page 1.

<sup>2</sup> Decision 13-2007, pages 176-177.

<sup>3</sup> T.D. Marriott, LLP, August 26, 2008, letter from Hydro Communities to Joe Acorn, page 1.

<sup>4</sup> T.D. Marriott, LLP, August 26, 2008, letter from Hydro Communities to Joe Acorn, page 2.

1 administrative costs...”<sup>5</sup> and that “(f)urther, the TGC concurs with the Board’s proposal “to  
 2 combine the Phase 2 review with the review of the NTPC’s inter-affiliate code of conduct and  
 3 conflict of interest guidelines...”<sup>6</sup>

4  
 5 By letter dated August 28, 2008, the Board indicated that although there may be separate  
 6 decisions, the Board decided that it would combine the review processes for the Phase 2 GRA  
 7 and NTPC’s responses to Directives 49 and 50. The Board proposed a draft schedule for the  
 8 proceeding.

9  
 10 By letter dated September 8, 2008, the Board indicated that it had received submissions from the  
 11 HC, TGC and NTPC, all of which expressed no concern with the Board’s draft schedule. The  
 12 Board therefore fixed a schedule for the proceeding. The proceeding included one round of  
 13 interrogatories from the Board and intervenors.

14  
 15 NTPC received interrogatories on September 12, 2008 from the HC (HC.NTPC-1 through  
 16 HC.NTPC-12) and the TGC in respect of both the GRA (TGC.NTPC-GRA-1) and the Code of  
 17 Conduct Review (TGC.NTPC-CCR-1 through TGC.NTPC-CCR-23). On September 19, 2008  
 18 NTPC received interrogatories from the Board (BR.NTPC-1 through BR.NTPC-9). NTPC  
 19 responded to all interrogatories by letter dated September 26, 2008.

20  
 21 **(a) Requested Relief**

22 The Corporation’s August 15, 2008 Phase II GRA and Rate Finalization Application set out in  
 23 detail the relief requested from the Board as follows<sup>7</sup>:

24 The Corporation is applying, pursuant to the provisions of the *Northwest*  
 25 *Territories Power Corporation Act* (“NWTPCA”) and the regulations made  
 26 thereunder, and pursuant to the provisions of the Public Utilities Act (“PUA”), for  
 27 an order or orders of the *Public Utilities Board* (“Board”):

- 28 a) Approving as final the Corporation’s interim retail, wholesale and industrial rates for  
 29 2006/07 and all previous periods.  
 30  
 31 b) Approving as final the Corporation’s proposed 2007/08 retail, wholesale and industrial  
 32 energy rates as outlined in Appendix A and Schedule A.2. The Corporation proposes to  
 33 maintain the existing customer and demand charges for all rate classes.  
 34

---

<sup>5</sup> Azad Merani, August, 26, 2008, letter from Thermal Generation Communities to Joe Acorn, page 1.

<sup>6</sup> Azad Merani, August, 26, 2008, letter from Thermal Generation Communities to Joe Acorn, page 2.

<sup>7</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page 1-1 line 3 through page 1-2 line 11.

- 1 c) Approving the consolidation of the 2006/07 and 2007/08 General Rate Application  
 2 shortfalls after transfers from the Diesel Communities Stabilization Fund; the Inuvik  
 3 Stabilization Fund; the Norman Wells Stabilization Fund and the Taltson Fuel  
 4 Stabilization Fund to offset the GRA Shortfall amounts as described in Appendix B and  
 5 shown in Schedule B.1.  
 6
- 7 d) Approving the adjusted shortfall collection riders as described in Appendix B and shown  
 8 in Schedule B.3.  
 9
- 10 e) Approving a change in the interest rate applicable to any outstanding shortfall balances in  
 11 place beyond October 1, 2009, as discussed in Appendix B. If the interest rate change is  
 12 not approved then the Corporation is seeking to recover the shortfall balances over a 12-  
 13 month period.  
 14
- 15 f) Approving automatic fuel stabilization fund and automatic water stabilization fund riders  
 16 as described in Appendix C and shown in Schedules C.1 and C.2.  
 17
- 18 g) Approving standardized dates for stabilization fund applications as described in  
 19 Appendix C.  
 20
- 21 h) Approving the Stand-by Rate proposal as described in Appendix D and Schedule D.  
 22
- 23 i) Approving the revisions to the Corporation's Terms and Conditions of Service discussed  
 24 in Appendix F.  
 25

26 And any further directives or approvals the Board deems necessary and prudent to provide.  
 27

28 It should be noted that during the round of interrogatories, the Board requested the Corporation  
 29 to provide an alternative rate design scenario to the one provided in the Application. The  
 30 Corporation complied with the Board's request in its response to BR.NTPC-1. In the  
 31 Corporation's view, the rate design approach illustrated in BR.NTPC-1 has considerable merit  
 32 and should be given due consideration by the Board. The Corporation believes that  
 33 implementation of the alternative approach outlined in BR.NTPC-1 could reasonably be  
 34 implemented in place of the approvals requested in parts b); d) and f) above, if the Board  
 35 determines that it prefers that rate approach.<sup>8</sup>  
 36

37 The Corporation's Written Argument in support of the Phase II Application is set out below  
 38 under the following headings:

- 39 • Background (Section 2)
- 40 • Finalization of Interim Rates for 2006/07 and All Previous Periods (Section 3)

---

<sup>8</sup> It should also be noted that the scenario in BR.NTPC-1 uses updated fuel price forecasts.

- 1 • Consolidation of the 2006/07 and 2007/08 GRA Shortfalls (Section 4)
- 2 • Adjustments to 2007/08 Base Rates, Stabilization Fund Riders and Shortfall Riders
- 3 (Section 5)
- 4 • Interest Rates on Outstanding Shortfall Balances (Section 6)
- 5 • Standardized Dates for Future Stabilization Fund Applications (Section 7)
- 6 • Stand-By Rates (Section 8)
- 7 • Terms and Conditions of Service (Section 9)
- 8 • Other Matters (Section 10)

9 With respect to the Code of Conduct Review, NTPC filed Policy No. A-3 ‘Guidelines for  
 10 Regulated versus Non-Regulated Business Activities’ on November 30, 2007 in response to  
 11 Directive 50 from Decision 13-2007. The Corporation filed its ‘Code of Conduct for Affiliate  
 12 Transactions’ with the Board on January 31, 2008 in response to Directive 49 of Decision 13-  
 13 2007. The Corporation has adopted the Code as filed with the Board which satisfies all  
 14 legislative and regulatory requirements of the NWT, including the issues set out in Board Order  
 15 13-2007. Policy No. A-3 ‘Guidelines for Regulated versus Non-Regulated Business Activities’  
 16 was approved by the Corporation’s Board of Directors on January 22, 2008, and has been  
 17 incorporated into the NTPC Code of Conduct.<sup>9</sup>

18  
 19 The Corporation’s primary concern in providing the Code of Conduct and Policy No. A-3 was to  
 20 be responsive to Directives 49 and 50 from Decision 13-2007. The Corporation sees value in the  
 21 Board and Intervenors understanding and testing the Corporation’s approach to these issues. In  
 22 the Corporation’s view, this review can help with future regulatory efficiency by ensuring there  
 23 are common understandings of the issues and the approach to addressing these matters in future  
 24 proceedings. To this end, the Board, in its review of NTPC’s code, can indicate if there are added  
 25 provisions that it expects would be valuable or advisable to include in NTPC’s Code. The  
 26 Corporation’s comments with respect to the Code of Conduct Review are set out in Section 11.

## 27 28 **2. Background**

### 29 **(a) *Public Utilities Act***

30 The *Public Utilities Act*<sup>10</sup> (“*PU Act*”) requires the Corporation to have its rates for electric service  
 31 approved by the Board and governs the nature and scope of any such approval. Specifically:  
 32

---

<sup>9</sup> Judith Goucher, January 31, 2008, letter from NTPC to Joe Acorn, page 1.

<sup>10</sup> R.S.N.W.T. 1988, c. 24 (Supp.).

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

3  
4 Section 63 requires NTPC to seek approval from the Board of its Terms and Conditions of  
5 Service.

6  
7 Section 23 empowers the Board to grant a wide range of relief in respect of the Application.

8  
9 Collectively, these provisions empower the Board to consider the various components of the  
10 Application and grant the relief requested by the Corporation.

11  
12 **(b) The Northwest Territories Power Corporation**

13 The Northwest Territories Power Corporation serves a population of approximately 43 thousand  
14 people spread across an area of 1.3 million square kilometers. NTPC provides generation and  
15 distribution services to residents in twenty-five (25) communities. Nineteen (19) of those are  
16 served by diesel generation, two (2) are served by other generation sources, priced relative to  
17 diesel prices, and the remaining four (4) communities are served by hydro generation. Seventy-  
18 five (75) percent of the generation is from hydro. Hydro is supplied to wholesale customers;  
19 Northland Utilities Yellowknife Limited and Northland Utilities NWT Limited in Hay River and  
20 surrounding area. Hydro Power also serves the Corporation's industrial customers, the Miramar  
21 Con Mine and the former Giant Mine, both in the Yellowknife area. The total electrical load is  
22 served by an array of discrete systems which are isolated and unconnected, necessitating  
23 independent planning for each one. Some of the challenges NTPC faces include low customer  
24 densities, extreme weather, logistical difficulties, and the lack of an integrated transmission  
25 system.

26  
27 The Corporation's last Phase II General Rate Application applied to the 2001/02 and 2002/03  
28 test years. Final rates related to that Phase II Application were approved in Decision 8-2003.  
29 Since that time, there have been adjustments to base rates on an interim basis effective February  
30 1, 2007<sup>11</sup> and January 1, 2008<sup>12</sup>.

31  
32 In filing its 2006/07 and 2007/08 Phase II Application, the Corporation had to consider a number  
33 of significant issues, namely, \$8.383 million in outstanding revenue shortfalls primarily related  
34 to the 2007/08 year revenue requirement, substantial balances in the fuel stabilization funds, and  
35 the escalation of the Snare/Yellowknife water stabilization fund outside of its approved operating  
36 range, requiring approximately \$1.654 million to return the fund within its operating range. In  
37 particular, it should be noted that volatile fuel prices affected all aspects of the Phase II

---

<sup>11</sup> Decision 2-2007.

<sup>12</sup> Decision 20-2007.

1 Application. At the time of the Corporation's Phase II Application, fuel prices had increased up  
 2 to 60 percent since the Corporation filed the Phase I Application in November, 2006. The  
 3 Corporation continues to face substantial volatility in fuel prices.

### 4 5 **3. Interim Rates for 2006/07 and All Previous Periods**

6 Wholesale, retail and industrial rates for 2006/07 effective February 1, 2007 were granted  
 7 interim approval in Board Decision 2-2007.<sup>13</sup> The Corporation's Application notes that it is  
 8 seeking final approval for interim retail, wholesale and industrial rates for 2006/07 and all  
 9 previous periods.<sup>14</sup>

10 Through an interrogatory to the Corporation, the HC inquired about the intent of the phrase "and  
 11 all previous periods" in the Corporation's requested approval on page 1-1 of the Application.  
 12 The Corporation's response noted that the statement was intended to ensure that there remain no  
 13 outstanding matters related to rates charged in previous periods including final approval for  
 14 industrial rates effective January 1, 2005 as approved on an interim basis in Board Order 4-  
 15 2005.<sup>15</sup>

16  
 17 The Corporation notes that the interim rates approved in Decision 2-2007 were subsequently  
 18 adjusted, on an interim basis, by Order 20-2007. The Corporation also notes that variances  
 19 between 2006/07 revenues at rates in place and approved 2006/07 test year revenue requirement  
 20 will be addressed by way of shortfall riders. Therefore, the Corporation submits that its request  
 21 for final approval of interim wholesale, retail and industrial rates for 2006/07 and all previous  
 22 periods is prudent and reasonable, and should be approved by the Board.

### 23 24 **4. Consolidation of the 2006/07 and 07/08 GRA Shortfalls**

25 In Decision 20-2007, the Board approved shortfall riders by community effective January 1,  
 26 2008 designed to collect the 2006/07 shortfall over approximately a 12 month period, stating:

27  
 28 For the purposes of calculating the Board-determined 2006/07 under recovery  
 29 rider, the Board has prorated the \$2.085 million amount to each of the  
 30 communities on the basis of the unrecovered balance as of March 31, 2007 and  
 31 used the 2007/08 volumes to arrive at the rider amount by community. These  
 32 calculations are shown in Schedule 1 of Appendix 2. The Board expects its  
 33 estimates would result in a reasonable 2006/07 rider by community intended to  
 34 recover the 2006/07 unrecovered amounts as of December 31, 2007 over a 12

---

<sup>13</sup> Decision 2-2007, page 5.

<sup>14</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page 1-1 lines 8-9.

<sup>15</sup> HC.NTPC-4.

1 month period, for purposes of interim rates. However, since these are estimates,  
2 NTPC is directed to update the 2006/07 unrecovered balances by community at  
3 the time it files its application for recovery of the 2007/08 revenue under  
4 recoveries and incorporate all revenue under recovery amounts at that time into a  
5 single rider.<sup>16</sup>

6 Consistent with the Board's direction, the Corporation is applying to consolidate the 2006/07 and  
7 2007/08 shortfall receivables into one shortfall receivable by community. Schedule B.1 of the  
8 application provided the calculation of the Consolidated Shortfall at March 31, 2008. Schedule  
9 B.1 included the following information:

- 10
- 11 • Adjustments to the 2006/07 and 2007/08 shortfalls to reflect the adjustment to brushing  
12 expenses consistent with the approach approved in Decision 16-2008.
- 13 • Transfers from the fuel stabilization funds credited against the 2007/08 shortfall  
14 receivable as described in the Corporation's December 18, 2007 filing and included in  
15 Schedule 3 of Appendix 2 to Decision 20-2007.
- 16 • Interest applied using the methods and rates approved in Decision 16-2008.
- 17

18 Schedule B.1 shows the consolidated 2006/07 and 2007/08 shortfall receivable balance at March  
19 31, 2008 of \$9.339 million. Schedule B.2 to the Application showed the forecast balance in the  
20 shortfall receivable at September 30, 2008. The Corporation provided this forecast in order to  
21 illustrate the amount that would need to be collected by an adjusted rider. However the shortfall  
22 receivable will continue to be reduced by actual collections for the period from April 1, 2008  
23 forward. Following collection of the consolidated shortfall, the Corporation will file a  
24 reconciliation of rider collections and shortfall balances.

25

26 No intervenors posed interrogatories to the Corporation with respect to the consolidation of the  
27 2006/07 and 2007/08 shortfalls or the calculation of the balance in the consolidated shortfall  
28 receivable at March 31, 2008. The Corporation submits that its calculation of the consolidated  
29 shortfall balance as at March 31, 2008 is consistent with the methods approved in Decision 16-  
30 2008 and should be approved.

## 31 **5. Adjustments to 2007/08 base rates, stabilization fund riders and shortfall riders**

32

33 In its Application, the Corporation applied for adjustments to 2007/08 base rates, stabilization  
34 fund riders and shortfall riders. The first step in the Corporation's proposed rate design reflected  
35 a change to 2007/08 interim base rates to implement the brushing expense adjustment to the  
36 Corporation's 2007/08 revenue requirement as ordered in Decision 4-2008. The adjustments to  
37 2007/08 interim base rates to reflect the reduced 2007/08 revenue requirement were shown in

---

<sup>16</sup> Decision 20-2007, page 5.

1 column G of Schedule A.2.1 of the Application. The Corporation's application also notes that it  
 2 is seeking to maintain its existing customer charges and demand charges for firm electricity  
 3 service for all customer classes.<sup>17</sup>

4  
 5 Following the adjustment to 2007/08 interim base rates to reflect the revised revenue  
 6 requirement, the Corporation applied a series of rate design criteria considering the need to  
 7 address the major rate adjustment requirement facing the Corporation and its customers. The  
 8 Corporation noted in its Application that the scale of adjustment required is such that the rate  
 9 design criteria traditionally applied by NTPC and the Board could not all be met simultaneously.  
 10 NTPC felt that intergeneration equity and the potential for future increases require that the  
 11 shortfall in fuel balances be collected by March 31, 2010 or as soon as possible.

12  
 13 Proposed base rates, shortfall riders and stabilization fund riders were presented in Schedule 1.1  
 14 of the Application. NTPC summarised rate design criteria used in the Application as follows:<sup>18</sup>

15  
 16 1) **Collect utility costs within a reasonable period of time:** In this regard, rates were designed  
 17 to include the following amounts:

- 18  
 19 a) Approximately \$5.8 million in annualized riders related to increases in fuel prices since  
 20 the last NTPC GRA to the present time (the "keep up" component of the diesel  
 21 communities, Inuvik and Norman Wells fuel funds (the "primary power fuel funds"));  
 22 plus  
 23  
 24 b) One time amounts of approximately \$15.4 million comprised of \$8.4 million for GRA  
 25 shortfalls per Schedule B.2, \$2.4 million for the Diesel Communities Fuel Fund, \$0.9  
 26 million for the Inuvik Fuel Fund, \$0.8 million for the Norman Wells Fuel Fund, \$1.4  
 27 million for the Yellowknife Fuel Fund, \$0.05 million for the Ft. Smith Fuel Fund, plus  
 28 \$1.7 million to bring the Snare-Yellowknife Water Fund to the trigger level.

29  
 30 All of which yields an annualized amount of approximately \$16.065 million. While this  
 31 does not precisely yield \$0 balances for each of the funds 18 months out (due to both  
 32 interest being charged, as well as: i) for the primary power fuel funds, forecast changes to  
 33 fuel prices over the coming 18 months, and ii) for the water and standby fuel funds,  
 34 anticipated charges to the funds over the coming 18 months) it does provide a reasonable  
 35 basis to begin to implement the rolling 6 months stabilization fund revision process  
 36 proposed by NTPC.  
 37

---

<sup>17</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page 1-1 lines 11-12.

<sup>18</sup> BR.NTPC-1 (a) and (c).

1 **2) Must avoid inter-community cross-subsidization where possible:** NTPC proposes to  
 2 recover all noted amounts from the communities or groups of communities where the costs  
 3 arise, consistent with the strict interpretation of community-based rates applied in NWT to  
 4 date.

5  
 6 **3) Within the above two constraints, must seek to not raise rates to any given customer**  
 7 **class by more than 15%:** While this criteria could be met for the shortfall component of the  
 8 application, it was not possible to achieve this rate impact constraint with respect to fuel fund  
 9 riders while maintaining separate stabilization fund riders to address fuel price variations and  
 10 stabilization fund balances for each stabilization fund.

11  
 12 In response to interrogatories posed by the Board, NTPC provided additional information  
 13 regarding options for rate designs for adjustments to 2007/08 base rates, shortfall riders and  
 14 stabilization fund riders. A comprehensive alternative approach to the rate design used in the  
 15 application can be developed to reprioritize the rate design criteria and adopt certain key  
 16 variations in the rate design methodologies for implementation as at November 1, 2008. The  
 17 Corporation set out the development of this alternative approach in response to BR.NTPC-1 as  
 18 follows:

19  
 20 **1) Base Rate Adjustments:** Implement the required base rate adjustments for the brushing  
 21 expense adjustment, as set out in the GRA Phase II Application.

22  
 23 **2) Stabilization Funds:** Per BR.NTPC-2(b) and BR.NTPC-4 (update for new fuel prices,  
 24 November 1, 2008 implementation, and other adjustments as described in that response),  
 25 implement two stabilization fund adjustment mechanisms:

26  
 27 a) **Crystallized “Catch-up”:** Per BR.NTPC-2(b), crystallize all fuel fund balances as at  
 28 October 31, 2008, as well as the amounts to which the Snare-YK water fund exceeds the  
 29 trigger levels as of that date, and charge to all customers on the system (including  
 30 industrial and wholesale including NUL(NWT)) on an equal cents/kW.h basis over 17  
 31 months (now must assume November 1, 2008 rate implementation date through  
 32 approximately March 31, 2010, or until fully collected). The levelized rider to be applied  
 33 is 1.62 cents/kW.h.

34  
 35 b) **“Keep up”:** Adopt an “iterative” approach to stabilization funds to target approximately  
 36 \$0 balances 17 months out (March 31, 2010) for all funds except the Snare-YK water  
 37 fund, which would target approximately the \$3 million trigger level. In preparing this  
 38 forecast, use updated fuel price forecasts for current price levels (effective as of  
 39 September 19, 2008) which are approximately US\$103/bbl (approximately US\$19/bbl  
 40 lower than in the Application).

1 **3) GRA Shortfall Riders:** Implement GRA shortfall riders as per the Application with the  
2 exception of those communities and customer classes which would see cumulative rate  
3 changes in excess of 15% at the time of implementation (November 1, 2008) including all  
4 riders and stabilization fund amounts - those customer classes and communities would be:

5  
6 **a) At November 1, 2008** have their GRA shortfall rider set such that their overall rate  
7 change is capped at 15%.

8  
9 **b) At April 1, 2009** implement a further increase as needed to target collection of the full  
10 shortfall within 12 months from that date, but in any event no more than 10%, (consistent  
11 with Board Decision 11-2008). Maintain all the shortfall riders in place until the full  
12 NTPC company-wide GRA shortfall balance is collected (i.e., do not turn off riders  
13 community by community).

14  
15 The specific outcomes of this rate design were set out in Tables 1 and 2 in the response to  
16 BR.NTPC-1 (a) and (c). These tables are repeated below:

17

1 **Table 1 Alternative Rate Design Approach- Rates to be Implemented November 1, 2008<sup>19</sup>**

2

Plant Number	Community	Proposed Stabilization Fund Balance Retirement Rider (\$/kWh)	Proposed Keep up Fuel Rider (\$/kWh)	Proposed Keep Up Water Rider (\$/kWh)	Proposed Shortfall Riders Effective Nov 1 2008				
					Residential (\$/kWh)	General Service (\$/kWh)	Lighting (\$/kWh)	Wholesale (\$/kWh)	Industrial (\$/kWh)
		B	C	D	E	F	G	H	I
101	Yellowknife	1.62	0.26	0.26				0.53	0.08
108	Behchoko	1.62	0.26	0.26	1.10	1.10	1.10		
109	Dettah	1.62	0.26	0.26	1.10	1.10	1.10		
104	Wha Ti	1.62	4.04		(4.01)	(4.01)	(4.01)		
105	Gameli	1.62	4.47		9.49	9.49	9.49		
110	Lutsel K'e	1.62	4.07		(0.57)	(0.57)	(0.57)		
201	Fort Smith	1.62	0.07		0.93	0.93	0.93	0.35	
203	Fort Resolution	1.62	0.07		0.93	0.93	0.93		
205	Fort Simpson	1.62	4.00		11.55	10.18	12.89		
206	Fort Liard	1.62	4.02		11.99	10.84	12.96		
207	Wrigley	1.62	4.33		25.18	26.62	33.15		
208	Nahanni Butte	1.62	6.22		35.73	42.96	44.52		
209	Jean Marie River	1.62	5.68		34.48	42.27	52.38		
301	Inuvik	1.62	3.23		4.54	4.54	4.54		
304	Norman Wells	1.62	5.54		(3.07)	(3.68)	(1.99)		
305	Tuktoyaktuk	1.62	4.20		(3.40)	(3.40)	(3.40)		
306	Fort McPherson	1.62	4.17		3.78	3.78	3.78		
307	Aklavik	1.62	4.37		(4.67)	(4.67)	(4.67)		
308	Deline	1.62	4.27		1.96	1.98	1.98		
309	Fort Good Hope	1.62	4.20		(3.36)	(3.36)	(3.36)		
310	Tulita	1.62	4.30		(5.67)	(5.67)	(5.67)		
311	Paulatuk	1.62	4.41		4.00	4.00	4.00		
312	Sachs Harbour	1.62	4.83		11.58	11.58	11.58		
313	Tsiigehtchic	1.62	4.38		(5.13)	(5.13)	(5.13)		
314	Colville Lake	1.62	5.05		(3.83)	(3.83)	(3.83)		
315	Ulukhaktok	1.62	4.16		(5.57)	(5.57)	(5.57)		

3

4

		Proposed Base Rates				
Plant Number	Community	Residential	General Service	Lighting	Wholesale	Industrial
		(\$/kWh)	(\$/kWh)	(\$/kWh)	(\$/kWh)	(\$/kWh)
		J	K	L	M	N
101	Yellowknife	-	-	-	13.47	10.48
108	Behchoko	23.01	28.78	89.90		
109	Dettah	23.02	28.83	52.25		
104	Wha Ti	83.44	77.37	137.75		
105	Gameli	114.11	133.49	151.15		
110	Lutsel K'e	73.85	88.34	120.22		
201	Fort Smith	15.12	11.85	22.96	7.55	
203	Fort Resolution	17.12	14.75	28.89		
205	Fort Simpson	54.93	45.84	63.87		
206	Fort Liard	59.34	51.85	101.73		
207	Wrigley	103.86	113.43	158.01		
208	Nahanni Butte	118.83	166.88	207.81		
209	Jean Marie River	103.08	155.02	222.41		
301	Inuvik	52.45	45.77	82.89		
304	Norman Wells	39.79	35.70	54.80		
305	Tuktoyaktuk	88.81	60.87	94.07		
306	Fort McPherson	72.25	85.30	81.90		
307	Aklavik	83.77	80.88	88.28		
308	Deline	75.55	70.86	63.70		
309	Fort Good Hope	70.42	81.43	82.44		
310	Tulita	87.47	84.43	101.17		
311	Paulatuk	115.01	108.24	128.20		
312	Sachs Harbour	135.02	125.47	145.98		
313	Tsiigehtchic	109.54	96.87	139.70		
314	Colville Lake	245.30	215.29	588.10		
315	Ulukhaktok	72.74	88.02	95.44		

5

6

		Percentage Change Compared to Existing Rates and Riders				
Residential	General Service	Lighting	Wholesale	Industrial		
O	P	Q	R	S		
			15.0%	15.0%		
11.4%	9.1%	3.8%				
11.3%	9.1%	5.1%				
1.8%	1.9%	1.1%				
8.0%	8.9%	8.1%				
3.5%	3.7%	2.2%				
			15.0%			
11.5%	14.7%	7.7%				
10.2%	11.8%	8.2%				
15.0%	15.0%	15.0%				
15.0%	15.0%	10.1%				
15.0%	15.0%	14.9%				
15.0%	15.0%	13.0%				
15.0%	15.0%	15.0%				
9.7%	11.0%	8.2%				
15.0%	15.0%	12.8%				
3.5%	3.9%	2.5%				
7.3%	8.0%	6.5%				
7.1%	7.5%	5.2%				
8.9%	7.3%	8.1%				
2.0%	2.2%	1.7%				
0.0%	0.0%	0.0%				
4.9%	5.2%	4.4%				
8.9%	9.5%	8.2%				
-0.2%	-0.2%	-0.2%				
8.3%	7.2%	2.5%				
0.4%	0.4%	0.3%				

<sup>19</sup> BR.NTPC-1, page 7.

1 **Table 2 Alternative Rate Design Approach Shortfall Rider Adjustments April 1, 2009<sup>20</sup>**

2

Plant Number	Community	Proposed Shortfall Riders Effective April 1 2009					Percentage Change Compared to Nov 2008 Rates and Riders					
		Residential	General Service	Lighting	Wholesale	Industrial	Residential	General Service	Lighting	Wholesale	Industrial	
		(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	O	P	Q	R	S	
		E	F	G	H	I						
101	Yellowknife					1.34					5.0%	10.0%
108	Behchoko	1.10	1.10	1.10			0.0%	0.0%	0.0%			
109	Dettah	1.10	1.10	1.10			0.0%	0.0%	0.0%			
104	Wha Ti	(4.01)	(4.01)	(4.01)			0.0%	0.0%	0.0%			
105	Garnet	9.49	9.49	9.49			0.0%	0.0%	0.0%			
110	Lutsel K'e	(0.57)	(0.57)	(0.57)			0.0%	0.0%	0.0%			
201	Fort Smith	0.93	0.93	0.93		1.17	0.0%	0.0%	0.0%		8.6%	
203	Fort Resolution	0.93	0.93	0.93			0.0%	0.0%	0.0%			
205	Fort Simpson	15.35	18.35	15.35			8.1%	10.0%	3.0%			
206	Fort Liard	13.36	13.84	12.96			1.8%	4.4%	0.0%			
207	Wrigley	36.47	35.87	33.15			8.4%	6.3%	0.0%			
208	Nahanni Butte	48.18	45.17	44.52			7.7%	1.0%	0.0%			
209	Jean Marie River	48.96	58.26	54.05			10.0%	7.8%	0.6%			
301	Inuvik	4.54	4.54	4.54			0.0%	0.0%	0.0%			
304	Norman Wells	(1.54)	(1.29)	(1.99)			3.5%	8.1%	0.0%			
305	Tuktoyaktuk	(3.40)	(3.40)	(3.40)			0.0%	0.0%	0.0%			
306	Fort McPherson	3.78	3.78	3.78			0.0%	0.0%	0.0%			
307	Aklavik	(4.67)	(4.67)	(4.67)			0.0%	0.0%	0.0%			
308	Deline	1.98	1.98	1.98			0.0%	0.0%	0.0%			
309	Fort Good Hope	(3.36)	(3.36)	(3.36)			0.0%	0.0%	0.0%			
310	Tulita	(5.67)	(5.67)	(5.67)			0.0%	0.0%	0.0%			
311	Paulatuk	4.00	4.00	4.00			0.0%	0.0%	0.0%			
312	Sachs Harbour	11.58	11.58	11.58			0.0%	0.0%	0.0%			
313	Tsiligetfelic	(5.13)	(5.13)	(5.13)			0.0%	0.0%	0.0%			
314	Cohville Lake	(3.83)	(3.83)	(3.83)			0.0%	0.0%	0.0%			
315	Uluhaktok	(5.57)	(5.57)	(5.57)			0.0%	0.0%	0.0%			

3  
4  
5 Although it does not strictly adhere to the longstanding “no cross-subsidization between  
6 communities” rate design criterion normally employed in the NWT, this alternative scenario  
7 exhibits some areas of significant merit. In particular, this rate design option recognizes the  
8 extraordinary circumstances surrounding fuel price increases in 2008 and implements an equal  
9 cents per kilowatt-hour for all communities and rate classes to retire existing balances in all fuel  
10 stabilization funds and to return the Snare-Yellowknife water stabilization fund to the trigger  
11 level. In situations where fuel costs have increased to this degree, maintaining a 15% cap on rate  
12 increases requires a mechanism to share some fuel costs across systems. Further, as the  
13 Corporation noted in its Application, the magnitude of cost pressures related to fuel price  
14 increases and the 2007/08 shortfall indicates that there is little to no ability to undertake rate  
15 rebalancing between communities and rate classes. This places pressure on the long-standing rate  
16 design objective to move toward revenue to cost coverage ratios of 95% to 105%. However, in  
17 the current circumstances the Corporation believes there is merit in the approach described in  
18 BR.NTPC-1. Rate design is always an exercise in achieving balance between sometimes  
19 competing rate objectives.

20  
21 The Corporation notes that other utility regulators faced with extraordinary circumstances have  
22 implemented rates that do not necessarily conform to the normal rate design criteria employed in  
23 the jurisdiction. In its Application the Corporation provided an example from the Manitoba

<sup>20</sup> BR.NTPC-1, page 8.

1 Public Utilities Board where that Board implemented an across the board rate increase to all rate  
2 classes in recognition of an unusually severe drought.<sup>21</sup>

3  
4 In the Corporation's view, the alternative rate design approach summarised in BR.NTPC-1 is  
5 preferable to the approach included in the Application. The Corporation submits that the rates  
6 summarised in Table 1 and Table 2 can be readily implemented if preferred by the Board, and  
7 deserve due consideration in this regard.

## 8 9 **6. Interest Rate Applicable Shortfall Balances**

10 In Board Decision 16-2008 the Board allowed the Corporation to charge interest at a rate of  
11 2.31% on the 2006/07 shortfall for the period from April 1, 2007 to December 31, 2007. For the  
12 period beyond December 31, 2007, the Board allowed NTPC to apply short-term interest to the  
13 actual outstanding receivable monthly at a level equal to 50% of the Bank of Canada Prime  
14 Business interest rate.<sup>22</sup> With respect to the 2007/08 shortfall, the Board allowed the Corporation  
15 to charge interest at a rate of 3.0% on a mid-year basis for 2007/08. Beginning April 1, 2008  
16 until full collection of the 2007/08 shortfall the Corporation is permitted to apply short-term  
17 interest monthly to the actual outstanding receivable at a level equal to 50% of the Bank of  
18 Canada Prime Business interest rate.<sup>23</sup> As a result of the Board's directions in Decision 16-2008,  
19 effective April 1, 2008 the Corporation charges short-term interest at a level equal to 50% of the  
20 Bank of Canada Prime Business interest rate monthly on the actual 2006/07 and 2007/08  
21 receivables.

22  
23 In its Application, the Corporation applied to collect the outstanding GRA shortfall over an 18  
24 month period in order to help mitigate the rate impact on customers.<sup>24</sup> However, the Corporation  
25 noted that the approved interest rate reflects a very low short-term interest rate. Further, the  
26 Corporation noted that it has a limited ability to obtain financing at short-term interest rates.  
27 Access to short-term financing continues to tighten during the current financial market  
28 instability. Therefore, the Corporation applied to adjust the interest rate applicable to the GRA  
29 shortfall receivable to a level equal to the Prime Business rate less 50 basis points to any shortfall  
30 balances outstanding beyond October 1, 2009.<sup>25</sup> In the event that the interest rate change is not  
31 approved, the Corporation noted that it would seek to recover the outstanding shortfall amounts  
32 over a 12 month period instead of the proposed 18 month period.<sup>26</sup> The 18-month collection

---

<sup>21</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page 1-7 line 20 through page 1-8 line 19.

<sup>22</sup> Decision 16-2008, page 17.

<sup>23</sup> Ibid.

<sup>24</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page 1-4 lines 2-4.

<sup>25</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page B-2 lines 8-10.

<sup>26</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page B-2 lines 11-3.

1 period already strains the Corporation's access to short-term financing and without an adjustment  
2 to the interest rate effective October 1, 2009, the Corporation cannot propose to carry the GRA  
3 shortfall receivable beyond that period.

4  
5 In response to an interrogatory from the TGC, the Corporation provided additional information  
6 related to its access to short-term financing. The Corporation noted that it has an unsecured \$20  
7 million operating credit line with its financial institution. The Corporation also noted that if it  
8 were to increase its operating line it would likely be subject to standby fees for any funds not  
9 used. This would increase the Corporation's finance expense and overall cost of borrowing to the  
10 detriment of customers.<sup>27</sup>

11  
12 The Corporation's application noted that it is applying to collect approximately \$15.430 million  
13 in receivables related to the GRA shortfall and stabilization funds as at October 1, 2008.<sup>28</sup> If  
14 three quarters of the credit line is being used to finance a regulatory shortfall, the Corporation's  
15 ability to use the operating line to fund capital investment (pending conversion to long-term  
16 debt) is limited. This could hinder the Corporation's ability to deliver capital investment that is  
17 required to maintain and improve the Corporation's infrastructure. Without access to the  
18 necessary level of short-term financing, the Corporation would have to delay, defer or forego  
19 capital projects it would otherwise pursue to maintain its service level to customers. Clearly this  
20 outcome would adversely affect customers and not be consistent with the guiding principles of  
21 utility regulation.

22  
23 The Corporation respectfully submits that its proposal to collect the outstanding shortfalls over  
24 an 18 month period and change the interest rate applicable to the shortfall to a level equal to the  
25 Bank of Canada Prime Business rate less 50 basis points effective October 1, 2009 is a  
26 reasonable proposal. This proposal balances the rate impact of the shortfall collection with the  
27 limitations on the Corporation's access to short-term financing and should be approved.

## 28 29 **7. Standardized Dates for Stabilization Fund Applications**

30 NTPC currently maintains six stabilization funds: five fuel stabilization funds (for the Diesel  
31 communities; the Snare/Yellowknife system; Inuvik; Norman Wells and Fort Smith) and one  
32 water stabilization fund for the Snare/Yellowknife system. The Corporation's stabilization funds  
33 were established pursuant to the 1995/98 Phase I Negotiated Settlement. Parties to the 1995/98  
34 Phase I Negotiated Settlement included the City of Yellowknife, Town of Inuvik, Miramar Con

---

<sup>27</sup> TGC.NTPC-GRA-5 (a).

<sup>28</sup> The sum of \$8.383 million related to the GRA shortfall; \$5.393 million related to the diesel stabilization funds and \$1.654 million related to the balance above the trigger level of the Snare/Yellowknife water stabilization fund on pages ES-i and ES-ii of the Application.

1 Mine Ltd. and NUL. In response to an interrogatory from the HC, the Corporation provided a  
2 copy of the 1995/98 Phase I Negotiated Settlement.<sup>29</sup>

3  
4 In its Application, the Corporation noted that one of the key attributes of the funds was the  
5 implementation of an automatic rider to collect or refund balances in the funds. The 1995/98  
6 negotiated settlement states:

7  
8 An “automatic” rider would come into effect, subject only to Board  
9 approval of the calculation of the amount of the rider, when the amount in  
10 the Fund exceeds the Fund range sufficiently such that the Corporation  
11 determines that it is prudent to implement a rider.<sup>30</sup>

12  
13 In its Application, the Corporation noted that fuel prices have been extremely volatile recently  
14 and that fuel price changes can contribute to balances or credits to a significant degree.<sup>31</sup> It is  
15 also important to note that there is currently no fuel cost component built into the 2007/08  
16 revenue requirement for the Snare/Yellowknife system.<sup>32</sup> Given the current fuel price volatility,  
17 the Corporation applied to file Stabilization Fund Adjustment Applications on a regular  
18 schedule. The Corporation requested approval to file Applications for the adjustments by  
19 February 15 and August 15 each year for rider adjustments to be implemented effective April 1  
20 and October 1 respectively.

21  
22 Through interrogatories to the Corporation, intervenors requested additional information and  
23 clarification with respect to NTPC’s proposal for future rider adjustments. The Corporation  
24 provided additional information in this regard, stating:

25  
26 To be specific, the Corporation’s proposal with respect to future revisions to  
27 stabilization funds is to make the process as routine and automatic as possible, as  
28 follows:

29  
30 **1) For the diesel communities, Inuvik and Norman Wells stabilization**  
31 **funds:** Each 6 months (April 1 and October 1) implement new stabilization

---

<sup>29</sup> 1995/98 Phase I Negotiated Settlement, attached to response HC.NTPC-8 (a).

<sup>30</sup> 1995/98 Phase I Negotiated Settlement, page 5, bullet (e) (iii).

<sup>31</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page C-7 lines 16-17.

<sup>32</sup> Pursuant to the current operating rules of the Snare/Yellowknife water stabilization fund the diesel costs forecast for the Snare/Yellowknife system in the 2007/08 test year would be charged to the water stabilization fund. As a result, the Corporation netted these diesel costs off of its 2007/08 revenue requirement. This treatment was reviewed in detail as part of the Corporation’s Phase I proceeding and approved in Directive 8 of Decision 17-2007.

1 fund riders that comprise 2 components: 1) for the “keep up” (or fuel price  
2 variance) component, ensure the base riders in place (1.000 index) recovers  
3 the difference between the weighted average price for fuel (as at the date of  
4 application) and the most recent GRA price (and based on forecast 12 month  
5 generation and weighted average GRA plant efficiencies); and, 2) for the  
6 “catch up” (or balance retirement) component, take the full fund balance and  
7 divide by the forecast 12 months sales to determine the base rider (1.000  
8 index). These values would be updated on a rolling basis at each 6 month  
9 update.

10  
11 **2) For the standby fuel funds (Fort Smith and Yellowknife):** Each 6  
12 months (April 1 and October 1) implement new stabilization fund riders that  
13 comprise only a “catch up” (balance retirement) component, based on  
14 recovering the full fund balance at the time of the application divided by the  
15 forecast 12 months sales to determine the base rider. These values would be  
16 updated on a rolling basis at each 6 month update.

17  
18 **3) For the Snare Yellowknife Water Stabilization Fund:** Each 6 months  
19 (April 1 and October 1) implement new stabilization fund riders that  
20 comprise only a “catch up” (balance retirement) component, based on  
21 recovering the amount by which the fund exceeds the \$3 million trigger  
22 (plus or minus) at the time of the application divided by the forecast 12  
23 months sales to determine the base rider. These values would be updated on  
24 a rolling basis at each 6 month update.

25  
26 The approach proposed by NTPC under (3) above could lead to water  
27 stabilization fund riders being reduced, for example, if the fund was not used  
28 within a 6 month period, but the sales were higher than forecast so collections  
29 were ahead of forecast.

30  
31 This approach to managing the stabilization funds is somewhat of an evolution  
32 when compared to the 1995/98 Negotiated Settlement, but is proposed to reflect  
33 the following improvements:

- 34  
35 • The rate regime and timing for riders would be more transparent  
36 and predictable.

- 1           •       The funds would, where possible, attempt to be forward-looking  
2                   rather than just seeking to recover balances at a given point in  
3                   time (i.e., via keep-up components to certain riders).  
4
- 5           •       The approach may in some cases lead to riders being in place  
6                   even when funds are within approved triggers, simply to help  
7                   avoid having the funds trend outside the triggers and  
8                   necessitating larger riders in future periods.  
9

10       Although intended to be straight-forward, predictable and essentially automatic,  
11       NTPC notes that there may arise circumstances that require some degree of  
12       modification of the above approach, due for example to forecast continuing low  
13       water, or excessive rate impact, which may lead to the need to occasionally  
14       consider slight modifications to the above methods, on a case by case basis.<sup>33</sup>  
15

16       The Corporation notes that this forward looking approach to developing the stabilization fund  
17       riders could help improve rate stability, compared to simply turning off riders when the fund  
18       balances are within the trigger but the best available forecasts indicate riders may be required  
19       again within a short period.  
20

21       By interrogatory to the Corporation, the Board asked why the Corporation allowed stabilization  
22       fund balances to build up to levels well in excess of the stabilization fund triggers. In its  
23       response, the Corporation noted<sup>34</sup>:  
24

- 25       1. It has not been possible in most cases to impose any further riders over the past 2 years,  
26         given that rate increases approaching the full 15% cap have been applied in a number of  
27         communities at each of February 1, 2007 and January 1, 2008.  
28
- 29       2. The extraordinary fuel price volatility experienced in 2008.  
30
- 31       3. The transfers from the fuel stabilization funds to offset the 2006/07 and 2007/08 shortfall  
32         receivables approved in Decision 20-2007. Had these transfers not been made, then the  
33         balances in the Norman Wells and Inuvik fuel stabilization funds would have been under  
34         the trigger amount and the Diesel Communities Fuel Stabilization fund would not have  
35         been significantly over the trigger.  
36

---

<sup>33</sup> HC.NTPC-2, page 3.

<sup>34</sup> BR.NTPC-3, page 2.

1 4. The water stabilization fund operates differently than the fuel stabilization funds. The  
2 water stabilization fund always requires the fund to move beyond the trigger level, as the  
3 rider is designed only to bring the balance back to the trigger level (i.e., once the fund hits  
4 the trigger there would still be no rider, as there is no defined amount yet to collect).  
5 Therefore, there should be some meaningful amount beyond the trigger in the water  
6 stabilization fund before a rider is implemented. This is consistent with the language in  
7 the 1995/98 negotiated settlement that stated with respect to the Snare/Yellowknife water  
8 stabilization fund “An ‘automatic’ rider would come into effect, subject only to Board  
9 approval of the calculation of the amount of the rider, when the amount in the Fund  
10 exceeds the Fund range sufficiently such that the Corporation determines that it is  
11 prudent to implement a rider”<sup>35</sup>

12  
13 Also, the water stabilization fund can be self-correcting over time depending on water  
14 flows. Improvement in water flows could alleviate the need for a rider if the fund close to  
15 a trigger.

16  
17 In the Corporation’s view, its proposed approach to two annual Stabilization Fund Adjustment  
18 Applications would benefit customers by providing more regular and predictable price changes  
19 and ensure fairness to future customer by improving the timing between when fuel costs are  
20 incurred and when those costs are collected from customers. The Corporation also notes that it  
21 proposed rider implementation dates for April 1 and October 1 to avoid rate adjustments during  
22 the summer and winter holiday periods. The Corporation respectfully submits that its proposal is  
23 consistent with the intent of the stabilization funds as agreed to in the 1995/98 Phase I negotiated  
24 settlement and is in the best interest of the Corporation and its customers and should be  
25 approved.

## 26 27 **8. Stand-by Rate proposal**

28 Board Directive 8 from Board Decision 3-2003 directed “the Corporation to file the results of a  
29 study assessing the cost of providing standby service together with proposed standby service  
30 agreement including proposals for interconnection standards, subscription periods, exit fees and  
31 re-subscription fee...”<sup>36</sup>

32  
33 NTPC completed a study of the principles of stand-by rate design. The results of the study and  
34 proposed rate design criteria were originally presented in the Corporation’s 2006/07 and 2007/08  
35 Phase I General Rate Application. Following comments from the Board and intervenors at the  
36 Phase I Technical Workshop, the Corporation withdrew the proposed Stand-by Rate Design  
37 criteria as the topic was better addressed concurrent with other Phase II matters. Appendix D to

---

<sup>35</sup> 1995/98 Phase I Negotiated Settlement. Page 5.

<sup>36</sup> Decision 3-2003, page 57.

1 the Application summarized NTPC's Stand-by rate proposal. The Corporation also provided a  
2 copy of its interconnection guidelines with its Phase I Application. These interconnection  
3 guidelines were approved on an interim basis in Decision 13-2007. The Corporation is now  
4 seeking final approval of the interconnection guidelines and these were attached to the  
5 Application in Appendix D.

6  
7 In its Application, the Corporation noted that it intends the stand-by rates to apply only to  
8 installations larger than 5kW. This will allow customers to pursue small scale alternative energy  
9 installations and capture any environmental or economic benefits associated with these  
10 projects.<sup>37</sup>

11  
12 NTPC's stand-by rate design framework was developed after reviewing stand-by rate  
13 frameworks in place at other Canadian utilities, as well as other literature on the topic. Three  
14 principals were developed. The first principle is that NTPC must have the capability of serving  
15 the full stand-by load during a system peak. The second principle is that stand-by rates must  
16 capture the full cost of providing service, and finally, stand-by rates have to account for the  
17 different load profiles of stand-by customers.<sup>38</sup>

18  
19 As outlined in the Application, the Corporation will enter into specific agreements with stand-by  
20 customers, which will be filed with the Board. NTPC will estimate whether stand-by service is  
21 technically feasible in each instance. Customers must agree to a minimum subscription period,  
22 exit and re-subscription fees, and they must agree to be charged the prevailing General Service  
23 energy rate in the applicable community for energy consumption. In addition, stand-by rates will  
24 be subject to periodic adjustment.<sup>39</sup>

25  
26 The Corporation proposes a rate of \$24/kW for stand-by service each month, for all  
27 communities. The uniform rate has been proposed to maintain rate schedule clarity for  
28 customers and ease of administration, as well as being consistent with levelized demand charges  
29 for General Service customers. The \$24/kW stand-by rate was formulated using the cost-of-  
30 service method in the 2001/03 Phase II GRA updated for 2007/08 costs and sales information.  
31 "For most of the thermal communities the full cost generation demand component is  
32 approximately \$24 each month."<sup>40</sup> Stand-by demand rates are higher than General Service  
33 demand rates because some of the demand related costs are generally recovered through the

---

<sup>37</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page D-1 line 18 through page D-2 line 19.

<sup>38</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page D-10 line 6 through page D-11 line 11.

<sup>39</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page D-11 line 14 through page D-12 line 11.

<sup>40</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page D-13 lines 11-13.

1 energy charge to general customers, whereas Stand-by customers tend to purchase far less  
2 energy.<sup>41</sup>

3  
4 The Board and the HC posed interrogatories to the Corporation with respect to its application for  
5 Stand-by Service rates. The HC inquired about the rationale for charging \$24/kW for stand-by  
6 service for general service customers in Fort Smith, when there is an excess of hydro capacity in  
7 the community. In its response, the Corporation indicated that charging a levelized \$24/kW was  
8 consistent with the existing levelized demand charge for firm General Service customers and was  
9 intended to maintain customer understandability and ease of administration. The Corporation  
10 also noted that, given the rate levels in those communities, in its view stand-by service would  
11 likely not be sought by customers in hydro communities.<sup>42</sup>

12  
13 The Board requested further information on the calculations and assumptions used to arrive at  
14 the uniform \$24/kW rate. NTPC provided the information requested and noted that in many of  
15 the communities where stand-by service was likely to be most attractive to customers, including  
16 Inuvik and Fort Simpson, the Generation Related Demand charge calculation was approximately  
17 \$24/kW.<sup>43</sup>

18  
19 No intervenors posed questions with respect to the Corporation's draft interconnection  
20 guidelines.

21  
22 The Corporation submits that the proposed Stand-by rate proposal, outlined in Appendix D and  
23 Schedule D, as well as the interconnection guidelines, granted interim approval at Decision 13-  
24 2007 are reasonable, and should be approved by the Board.

## 25 26 **9. Terms and Conditions of Service**

27 As part of its 2006/07 & 2007/08 Phase I Application, the Corporation proposed certain changes  
28 to its Terms and Conditions of Service. These changes included an amendment to replace  
29 Section 13.2 with a limitation clause to prevent a claim for loss, injury or damage brought more  
30 than 180 days after the date of the occurrence of the incident which resulted in the loss. During  
31 the Phase I oral hearing, the Corporation withdrew this proposed limitation period. The  
32 Corporation proposed other changes to Section 13.2 in its Phase I reply argument.

33  
34 Directive 23 of Decision 13-2007 directed the Corporation to include this proposed change in its  
35 Phase 2 filing in order to give intervenors and customers the opportunity to respond to it.  
36

---

<sup>41</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page D-12 line 13 through D-13 line 4.

<sup>42</sup> HC.NTPC-11.

<sup>43</sup> BR.NTPC-8.

1 As part of its Phase 2 application, the Corporation attached a copy of the Terms and Conditions  
2 of Service with blacklined revisions to Section 13.2 and associated revisions to section 4.1 and  
3 section 14.1<sup>44</sup> and requested approval of the revised Terms and Conditions of Service.

4  
5 No intervenors posed questions on this matter.

6  
7 The Corporation submits that the proposed changes to Section 13.2, and associated changes to  
8 Sections 4.1 and 14.1 are reasonable and should be approved by the Board.

## 9 10 **10. Other Matters**

11 This section of the Corporation's argument addresses matters for which the Corporation is not  
12 seeking Board approval, but which were topics canvassed during the interrogatories.

### 13 14 **(a) Time-of-Use Rates**

15 In Decision 3-2003, the Board directed NTPC to "investigate the benefits and market potential  
16 for time-of-use rates and address this matter at the time of the next GRA."<sup>45</sup> The Corporation  
17 responded to this directive in Appendix F of the Application, stating that with respect to the  
18 Thermal Communities, there would be little to no cost savings as a result of time-of-use rates but  
19 there would be added costs including new metering technology and billing software adjustments.  
20 With respect to the Snare/Yellowknife and Taltson hydro systems, the Corporation noted that at  
21 present these systems have very limited diesel generation requirements, related largely to time of  
22 hydro unavailability, rather than capacity or peaking requirements. Therefore diesel requirements  
23 are difficult to predict and are not necessarily concurrent with peak time periods or seasons. The  
24 Corporation noted that when diesel generation is required more frequently a time-of-use rate  
25 structure may have more potential benefits. As a result, the Corporation indicated it is not  
26 proposing time-of-use rates at this time. The Corporation also noted that it was proposing a  
27 meeting with the Board and Northland Utilities on this topic.<sup>46</sup>

28  
29 Through interrogatories to the Corporation, the HC and the Board requested additional  
30 information related to time-of-use rates. The HC sought additional information with respect to  
31 when significant diesel generation will be required to meet peak demand on the YK system and  
32 also a copy of the letter from NTPC and NUL to the Board. The Corporation provided a copy of  
33 the letter, but indicated that it could not at present predict when there would be substantial diesel  
34 generation required for the Snare Yellowknife system.<sup>47</sup> Diesel requirements are difficult to

---

<sup>44</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page F-4 lines 1-15 and Appendix F.

<sup>45</sup> Decision 3-2003, page 57.

<sup>46</sup> NTPC 2006/07 and 2007/08 Phase II General Rate Application, page F-2 line 10 through page F-3 line 16.

<sup>47</sup> HC.NTPC-12.

1 predict since current diesel requirements relate largely to hydro unavailability (due to low water,  
2 capital projects or unplanned and unforeseen outages) and not peaking or capacity requirements.

3  
4 The Board sought additional information on load and generation patterns for July and December.  
5 This information was provided in the response BR.NTPC-9.<sup>48</sup> The Board also sought comments  
6 on the role time-of-use rates could play in forestalling diesel generation additions for the Snare  
7 Yellowknife system and further explanation on why NTPC considers there is little to no benefit  
8 in the thermal communities of shifting load between daily or seasonal periods.<sup>49</sup>

9  
10 In response to the Board's question, NTPC noted that in theory demand management methods  
11 could potentially provide system benefits on the Snare/Yellowknife system. However, in the  
12 Corporation's view, time-of-use rates would need to be undertaken in conjunction with NUL  
13 Yellowknife. The Corporation noted that it is open to pursuing these discussions with NUL  
14 Yellowknife and the Board.<sup>50</sup>

15  
16 With respect to the thermal communities, the Corporation stated that the short-run marginal cost  
17 of generation does not vary materially by time of day. The primary theoretical advantage of  
18 demand management through time-of-use rates is potentially delaying or deferring the  
19 installation of new generation facilities to meet growing system peaks. The Corporation noted  
20 that it is extremely rare for NTPC to install new generation for capacity reasons alone and that it  
21 might take many years for customers to see any potential rate benefits. The Corporation noted  
22 that there would be additional costs to implement time-of-use rates.

23  
24 Further, the Corporation noted that the metered customers in the thermal communities are  
25 residential or general service customers and that time-of-use rates for these types of customers  
26 are not the norm in other Canadian jurisdictions. In the Corporation's view time-of-use rates  
27 would be complicated and difficult to explain and difficult to implement. Time-of-use rates  
28 would be also be confusing for customers and difficult to understand how to adjust their power  
29 use.

30  
31 Achieving benefits from a time-of-use rate structure would be entirely reliant on the ability of  
32 customers to shift loads between times of day or season. In the Corporation's view residential  
33 and small general service customers have much less ability to load shift than industrial  
34 customers. Therefore in the balance of considerations the Corporation indicated that it does not  
35 believe time-of-use rates would provide enough benefits. To offset the additional costs. Instead,

---

<sup>48</sup> BR.NTPC-9 (a) and (b).

<sup>49</sup> BR.NTPC- 9 (c) and (d).

<sup>50</sup> BR.NTPC-9 (c).

1 the Corporation indicated that it focuses on general conservation efforts in order to manage both  
2 energy consumption and demand requirements.<sup>51</sup>

3  
4 The Corporation is not seeking approval of a time-of-use rate structure at this time and  
5 respectfully submits that it should not be directed to investigate the potential for time-of-use rates  
6 in the Thermal Communities at this time. As noted, the Corporation is open to discussion with  
7 the Board and NUL Yellowknife with respect to the merits of time-of-use rates for the  
8 Snare/Yellowknife system.

9  
10 **(b) Potential Directive to Achieve Certain Revenue to Cost Ratios in the Next**  
11 **Phase 2 GRA**

12 Through interrogatory to the Corporation, the Board requested comments on a potential direction  
13 from the Board that the revenue cost coverage ratios in the next Phase 2 GRA must conform to a  
14 specific set of ranges.<sup>52</sup> The Corporation notes that many of the communities with revenue to  
15 cost ratios below 95%, including for example Fort Resolution, Jean Marie River and Nahanni  
16 Butte, received 15% rate increases as approved in Decision 8-2003 as well as substantial rate  
17 increases effective February 1, 2007<sup>53</sup> and January 1, 2008.<sup>54</sup>

18  
19 The Corporation's response indicated that such a direction could be issued by the Board as a  
20 future rate design criteria that NTPC could seek to meet. At that time, NTPC's proposals could  
21 be assessed by the Board based on the extent to which the proposed rates meet this criteria in  
22 light of other relevant criteria. The Corporation noted that it was likely that this new criteria  
23 could not be met simultaneously with the Board's other rate design criteria including a 15% cap  
24 on rate increases but that the balance between different rate design criteria was a suitable matter  
25 to be addressed at the time of the next GRA.

26  
27 The Corporation also notes that many of the communities it serves have very small customer  
28 numbers and energy sales. When major capital projects are required, such as a new power plant  
29 or an extensive distribution upgrade, this can have an extreme impact on the community's  
30 revenue requirement and rates cannot be increased enough with a 15% cap to make up this  
31 revenue requirement shortfall. Further, when one community's rates are lower than 100%  
32 revenue to cost coverage it creates upward pressure on other community revenue to cost  
33 coverage ratios. Therefore, maintaining a 15% cap on rate increases in the future will mean that  
34 some communities will be outside of the 95% to 105% revenue to cost coverage ratio.

---

<sup>51</sup> BR.NTPC-9 (d).

<sup>52</sup> BR.NTPC-5.

<sup>53</sup> Rates as approved in Decision 2-2007.

<sup>54</sup> Rates as approved in Decision 20-2007.

1 **11. Code of Conduct Review**

2 As noted in Section 1 of this Argument, the Corporation believes there are benefits to a review of  
 3 its Code of Conduct and affiliate transaction policy to improve transparency and understanding  
 4 of these issues in future regulatory proceedings. This section sets out the Corporation's  
 5 comments with respect to certain matters canvassed by the Board and intervenors through  
 6 interrogatories to the Corporation.

7  
 8 **(a) Purpose of Code of Conduct**

9 As a preamble, the Corporation notes that there appears to be considerable confusion over the  
 10 concept of a Code of Conduct governing corporate behaviour, and the simple matter of  
 11 determining a fair cost allocation between affiliates.<sup>55</sup>

12  
 13 The Corporation's fundamental goal in developing its Code of Conduct was to address the  
 14 concerns noted by the Board in Decision 17-2007 in a manner that also accounted for the  
 15 Corporation's operating environment, which currently involves a limited competitive  
 16 environment, small volume and value of inter-affiliate transactions and limited available  
 17 resources that are ultimately paid for by its customers.<sup>56</sup>

18  
 19 The Corporation notes that for basically every other Crown electrical utility it is aware of that  
 20 maintains an inter-affiliate Code of Conduct (BC Hydro, Hydro Quebec, NB Power  
 21 Transmission) the code is intended primarily to govern wholesale competitive transmission  
 22 access, or competitive services provided "downstream of the meter". By contrast, all regulated  
 23 power sales within the jurisdiction of the NWT PUB are pursuant to monopoly franchises where  
 24 no retail competition is allowed. Further, NTPC does not sell services downstream of the  
 25 meter.<sup>57</sup>

26  
 27 With respect to appropriate methods for cost tracking affiliate transactions for a Crown utility,  
 28 the Corporation provided examples of two Crown utilities in Canada, Manitoba Hydro and  
 29 Newfoundland and Labrador Hydro, that have inter-affiliate cost tracking and allocation methods  
 30 that have been reviewed by their regulators.<sup>58</sup> Both of these utilities have inter-affiliate  
 31 transactions that are substantially larger than those between NTPC and its affiliates.<sup>59</sup>

32  


---

<sup>55</sup> TGC.NTPC-CCR-7 (a).

<sup>56</sup> NTPC letter to NWT PUB dated January 31, 2008, attached to response HC.NTPC-1 (a).

<sup>57</sup> TGC.NTPC-CCR-6 (a).

<sup>58</sup> TGC.NTPC-CCR-7 (a).

<sup>59</sup> TGC.NTPC-CCR-7 (b) Attachment 3 page 6.

1           **(b)     Development of Inter-Affiliate Transaction Policy and Code of Conduct**

2     The TGC posed questions to the Corporation with respect to the process used to develop NTPC  
3     Policy No. A-3<sup>60</sup> and whether the Code of Conduct is simply a formalization of NTPC's current  
4     processes.<sup>61</sup>

5  
6     In its response, the Corporation noted that Policy No. A-3 was prepared internally and with legal  
7     counsel. The policy was approved by NTPC's Board of Directors based on its suitability for  
8     NTPC's specific unique operations.<sup>62</sup> The Corporation also noted that the Code of Conduct is  
9     more than a formalization of NTPC's current processes. The Code of Conduct involves more  
10    documentation, employee education and integration into budget processes. Further, in the Code  
11    of Conduct NPTC undertakes to do the following new activities:

- 12
- 13       • Prepare annual descriptions of inter-affiliate transactions which will form the basis of the  
14       annual budget for NTPC to provide inter-affiliate services. These will be an offset to  
15       regulated costs.
  - 16
  - 17       • Internal quarterly reports on inter-affiliate transactions and costs incurred in the provision  
18       of services and assets to affiliates. An annual report on these transactions will be prepared  
19       and filed with the PUB as part of future General Rate Applications.<sup>63</sup>

20

21    The Corporation also noted that it is not proposing or adopting an ATCO style code.<sup>64</sup> The scale  
22    and volume of inter-affiliate transactions simply are not at all comparable between NTPC and  
23    ATCO. NTPC's proposed code of conduct is a "made in the North" approach that is appropriate  
24    for the type and scale of affiliate transactions applicable to NTPC. It is not clear to the  
25    Corporation what precise terms or provisions exist in the ATCO code that would be relevant to  
26    NTPC that are not for all intents and purposes addressed by NTPC's code.<sup>65</sup> However it is clear  
27    to the Corporation that the ATCO code requires each affiliate to undertake added costs, for  
28    example the requirement to appoint a Compliance Officer. In the Corporation's view this is an  
29    unnecessary expense to impose on rate payers given the current scale of inter-affiliate  
30    transactions. No such costs were included in the Corporation's approved 2006/07 and 2007/08  
31    revenue requirements.

---

32

<sup>60</sup> TGC.NTPC-CCR-4 (b).

<sup>61</sup> TGC.NTPC-CCR-1 (a).

<sup>62</sup> TGC.NTPC-CCR-4 (b).

<sup>63</sup> TGC.NTPC-CCR-1 (a) and (b).

<sup>64</sup> TGC.NTPC-CCR-8 (d).

<sup>65</sup> TGC.NTPC-CCR-9 (a), (b) and (c).

1           **(c) Northwest Territories Hydro Corporation Act**

2 Through an interrogatory to the Corporation, the Board requested information on the reasons that  
3 led to the decision to place the Taltson expansion project under the control of the NT Hydro and  
4 outside of the regulated electrical system. The Board also requested information regarding  
5 NTPC's position with respect to that matter. In its response the Corporation noted the following:  
6

- 7           1. The decision to exempt the Taltson Expansion project from regulation by the PUB was  
8 not NTPC's to make. The exemption results from legislation passed by the NWT  
9 legislature.
- 10
- 11           2. The Taltson Expansion project's exemption under the Public Utilities Act would apply to  
12 the project regardless of what company undertakes it whether that company is NTPC,  
13 NTCH, an Aboriginal joint venture or some other entity.
- 14
- 15           3. The project is not under the control of NT Hydro and is not contemplated to be developed  
16 by NT Hydro. The present expectation is that if the project were to go ahead, it would be  
17 under the control of Deze Energy Corporation, an Aboriginal joint venture. NTEC (03), a  
18 subsidiary of NT Hydro is a minority partner in Deze Energy.<sup>66</sup>  
19

20           **(d) Taltson Expansion Advantages and Disadvantages to Regulated Customers**

21 The Board requested information on the potential advantages and disadvantages to regulated  
22 customers of the decision to exempt the Taltson Expansion project from PUB regulation. In  
23 response, the Corporation indicated that there would be no disadvantages to NTPC and its  
24 customers if the Deze Energy Corporation developed the new Taltson project as a non-regulated  
25 project.<sup>67</sup> The Corporation noted the following:  
26

- 27           1. If the Taltson Expansion project proceeds, NTPC's regulated customers will continue to  
28 have access to the existing 18 Mega-watt capacity of hydro power at Taltson. There will  
29 be a Joint Operating Agreement in place to ensure that NTPC's regulated customers have  
30 priority for up to 18 Mega-watts of power.<sup>68</sup>  
31
- 32           2. The Corporation does not anticipate any significant difficulties in having its hydro system  
33 regulated and Deze's being unregulated. The expansion facility will have all its own  
34 assets, with the exception of shared use of the airstrip and camp facilities.<sup>69</sup>

---

<sup>66</sup> BR.NTPC-7 (a).

<sup>67</sup> BR.NTPC-7 (a).

<sup>68</sup> BR.NTPC-7 (d).

<sup>69</sup> BR.NTPC-7 (c).

- 1  
2 3. The possible Taltson Expansion project is not in competition with NTPC as there is no  
3 need for that quantity of power by NTPC. The Taltson Expansion project suits an  
4 unregulated framework since the proposed customers (the diamond mines) are not  
5 currently regulated customers; are not located in an area covered by an existing franchise  
6 and already have their own generation in place. Further, the Taltson Expansion project  
7 requires significant upfront speculative investment, which is not consistent with a  
8 potential future ROE at the levels typically approved by the PUB.<sup>70</sup>

9  
10 Further, the Corporation notes that to the extent any entity sought to charge regulated ratepayers  
11 for any costs related to a facility (capital costs, facility lease costs, power purchase costs from an  
12 unregulated project owner), the PUB would have to approve such cost recovery in rates.<sup>71</sup>  
13 Because the project is a non-regulated project, regulated ratepayers are insulated from any  
14 planning and study costs that might be required before the project can be built or any cost  
15 overruns the project incur if it is developed.

16  
17 With respect to potential advantages to NTPC and its regulated customers, the Corporation noted  
18 that the Nonacho dam that regulates the water for Taltson will require upgrading in the next 10  
19 years at a cost of \$10-\$20 million. Successful completion of the Taltson project may see this dam  
20 upgraded substantially or entirely by the Taltson Expansion project at considerable savings to the  
21 regulated customers.<sup>72</sup>

### 22 23 (e) Affiliate Transactions and Cost Tracking

24 The Board and the TGC posed several questions with respect to cost tracking of affiliate  
25 transactions.

26  
27 In its responses the Corporation noted the following:

- 28  
29 1. At present, the current level of activity is extremely low. Overhead charges for each of  
30 the years 2004/05 through 2007/08 have been approximately \$150,000, almost entirely  
31 related to NTEC (03).<sup>73</sup> This represents less than 0.2% of NTPC's total 2007/08 regulated  
32 revenue requirement.

33  

---

<sup>70</sup> TGC.NTPC-CCR-6 (d).

<sup>71</sup> TGC.NTPC-CCR-14 (f).

<sup>72</sup> BR.NTPC-7 (a).

<sup>73</sup> TGC.NTPC-CCR-23 (a).

- 1 2. NTPC has developed overhead allocation rates for salaries. The allocation rates were  
 2 developed based on discussions with staff who spend part of their time working with  
 3 NTEC (03). In 2007/08 these salary allocations total approximately \$100,000. Supplies  
 4 and overhead allocations are developed in a similar manner and total approximately  
 5 \$50,000 in 2007/08.<sup>74</sup>  
 6
- 7 3. Activities that NTEC (03) undertakes on its own, such as leases for office space, purchase  
 8 of supplies and services, consulting services and similar expenses are incurred directly by  
 9 NTEC (03) and do not flow through NTPC.<sup>75</sup>  
 10
- 11 4. Where an affiliate requires a capital asset, the affiliate purchases the asset directly and is  
 12 responsible for its own financing and amortization expense. If NTPC coordinates the  
 13 purchase the affiliate is charged overhead on the asset to account for the administrative  
 14 cost of purchasing the asset.<sup>76</sup>  
 15
- 16 5. Costs charged to affiliates at present are an offset (or reduction) to regulated utility costs,  
 17 to the benefit of ratepayers. For the foreseeable future it is not contemplated that NTPC  
 18 would receive services from affiliates, however, if that were to change, a similar process  
 19 would be established to track the receipt of services and assets provided by non-regulated  
 20 affiliates and the corresponding costs incurred by NTPC.<sup>77</sup>  
 21
- 22 6. Additional steps that will be undertaken to improve documentation of transactions and  
 23 enhance inter-affiliate transparency include segment reporting in financial statements;  
 24 budget reviews of affiliate transactions and employee education with respect to the  
 25 treatment of inter-affiliate transactions.<sup>78</sup>  
 26

27 **(f) Responsibilities of Board of Directors**

28 The TGC requested additional information in order to assess the impact of overlapping  
 29 management and Board of Directors of NT Hydro and its subsidiaries. In its response, the  
 30 Corporation provided a list of the Officers of NT Hydro and its subsidiaries. The Corporation  
 31 notes that while three individuals hold similar titles as Officers of these Corporations, the scale  
 32 of duties and functions are often very different given the nature of each company and its level of  
 33 activity. For example, NT Hydro is essentially a holding company and therefore has very limited

---

<sup>74</sup> TGC.NTPC-CCR-23 (a).

<sup>75</sup> TGC.NTPC-CCR-1.

<sup>76</sup> TGC.NTPC-CCR-21 (c).

<sup>77</sup> TGC.NTPC-CCR-1.

<sup>78</sup> TGC.NTPC-CCR-22 (a).

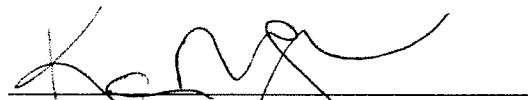
1 activity.<sup>79</sup> In the Corporation's view this reinforces the reasonableness of its approach to inter-  
2 affiliate transactions and cost tracking.

3  
4 The Corporation also noted that NT Hydro and NTPC directors have fiduciary duties that flow  
5 from their incorporating statutes and the Financial Administration Act. New directors are  
6 provided a detailed Director's Orientation, including briefings on the legal duties of Directors.<sup>80</sup>  
7

8 In summary, the Corporation believes that its responses to Directives 49 and 50 from Decision  
9 13-2007 are suitable and cost effective given the limited scale of affiliate transactions. The  
10 Corporation recognizes that the Board has the ability to review NTPC's cost-tracking  
11 mechanisms related to affiliate transactions in order to test the reasonableness of those  
12 transactions as they may impact NTPC's regulated customers. Therefore, the Corporation  
13 welcomes comments from the Board on adjustments to language or mechanisms to be included  
14 in the Code of Conduct and Policy No. A-3, in order to help ensure the Board has the  
15 information it requires in the future to assess the reasonableness of inter-affiliate cost tracking in  
16 future regulatory proceedings.

17 **ALL OF WHICH** is respectfully submitted this 14<sup>th</sup> day of October, 2008.

18  
19 **Borden Ladner Gervais LLP,**  
20 **Counsel for the Northwest Territories Power**  
21 **Corporation**

22  
23   
24  
25 Per: Karen A. McHugh

---

<sup>79</sup> TGC.NTPC-CCR-11 (a).

<sup>80</sup> TGC.NTPC-CCR-11 (b), (c) and (d).