

1 **Directive 1**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to reduce the opening plant**
4 **balance for 2006/07 by \$193,000 being that portion of the rate base addition for**
5 **the Fort McPherson plant that has not been explained nor demonstrated to be a**
6 **prudent expenditure by NTPC.**

7

8 **Response**

9

10 The Corporation notes the Board's statement on page 10 of Decision 13-2007 that
11 "Given that the plant fire repair deductible is already included as a charge against the
12 RFID in 2005/06, the Board does not find NTPC's explanation in BR.NTPC-27 that the
13 deductible on plant rebuild in the sum of \$193,000 included again as a component of
14 the plant rebuild costs, to be a credible explanation of the costs comprising the net
15 capital additions in relation to the Fort McPherson plant."

16

17 The Corporation has reviewed the Board's directive and the information provided in the
18 responses to BR.NTPC-27 (b) iii; TGC.NTPC-55 and TGC.NTPC-34 and has
19 determined that clarifications with respect to the information provided in these
20 responses is required.

21

22 The total insurance deductible for the Fort McPherson plant was \$250,000. Of this,
23 \$9,000 was related to Aadrii residual heat assets. Of the remaining \$241,000, \$193,000
24 was related specifically to the plant re-build and the remaining \$48,000 to other items
25 (e.g. debris removal, inventory replacement, etc). These components of the deductible
26 are itemized in the response to TGC.NTPC-34 (f).

27

28 The Corporation's response to TGC.NTPC-55 (b) indicated a charge of \$315,000 to the
29 RFID in 2005/06 related to the plant fire, insurance deductible and items not covered by
30 insurance. A breakdown of the \$315,000 charge is provided in the response to

1 TGC.NTPC-34 (b) in the column labeled “Non-insurable Costs (RFID)”.¹ The table in the
2 response to TGC.NTPC-34 (b) shows that the “Non-Insurable Costs (RFID)” do not
3 include any amounts related to the plant re-build.

4
5 The Corporation’s response to BR.NTPC-27(b)(iii) provided a breakdown of the \$2.911
6 million net additions to ratebase to reconstruct the Fort McPherson power plant. The
7 table provided in this response shows that \$193,000 of the \$2.911 million was related to
8 the deductible on the plant rebuild and that this amount was charged to the Reserve for
9 Injuries and Damages (“RFID”). The table in BR.NTPC-27(b)(iii) correctly summarizes
10 the accounting treatment for these charges however, the Corporation’s application
11 incorrectly reflected the \$193,000 as part of the capital costs of the project and not as
12 being charged to the RFID.

13
14 Therefore, the Corporation agrees that the \$193,000 related to the insurance deductible
15 for the capital replacement should have been charged to the RFID and not capitalized
16 as a project cost. Therefore in its refiling the Corporation has implemented the following
17 adjustments to its revenue requirement:

- 18
- 19 • The net addition to ratebase related to the Fort McPherson plant rebuild in
20 2004/05 has been reduced by \$193,000.
 - 21 • A charge to the RFID of \$193,000 has been added in 2004/05. This change is
22 reflected in the Corporation’s capitalization as a decrease in no-cost capital in
23 Schedule 3.6.
 - 24 • The return on rate base has been adjusted to reflect this correction.
 - 25 • Amortization expense in the 2006/07 and 2007/08 test years has also been
26 reduced by approximately \$7,000 in each test year.
- 27

¹ TGC.NTPC-34 (b) shows this amount as \$316,000 due to rounding.

1 **Directive 2**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to reduce the cost of the Aklavik**
4 **plant addition by 50% of the cost increase resulting from the delays. The costs to**
5 **be included for the 50% risk sharing adjustment are overheads and Allowance for**
6 **Funds Used During Construction (“AFUDC”) resulting solely from the delays in**
7 **completion of the plant caused by the unforeseen length of time spent on**
8 **community consultations and the fire at Fort McPherson.**

9

10 **Response**

11

12 It appears from the wording of Decision 13-2007 that the Board may be under the
13 misunderstanding that the Aklavik project cost estimates increased from \$3.5 million to
14 \$4.9 million at the time the project permit was submitted to the Board. In the Aklavik
15 major project permit application, which was approved in Decision 11-2006, the
16 Corporation noted that the estimated original project budget for the Aklavik plant
17 addition was \$3.5 million. Appendix A of the major project permit application identified
18 that the estimated revised project budget was \$4.4 million. Appendix A also included a
19 footnote to indicate that the addition of AFUDC and overheads brought the estimated
20 “all in” project budget to \$4.9 million. Neither the application nor the interrogatories
21 spoke to the estimated original “all in” project budget, which with the addition of AFUDC
22 and overheads was \$4.3 million. The difference between the estimated original and the
23 estimated project permit budget was therefore \$0.6 million which was explained as
24 relating to higher costs brought on in part due to the Corporation diverting resources to
25 address the Fort McPherson fire and dedicating time and effort to consult with the
26 community of Aklavik on the project.

27

28 The Corporation maintains that it was acting prudently when it responded to the Fort
29 McPherson fire and the need to quickly rebuild a permanent power plant in Fort
30 McPherson. It is further maintained that any utility, acting reasonably, would expect an

1 emergency situation such as the Fort McPherson fire to cause a review of projects
2 currently in progress and to determine which of those projects might be delayed, without
3 impinging on the “duty to serve”, in order to reallocate resources to address the
4 emergency situation.

5
6 Further, the Corporation maintains that engaging in community consultation such as the
7 process that took place in Aklavik was appropriate, in consideration of the magnitude of
8 the project, and necessary in consideration of the long term power supply needs of a
9 community that has issues with flooding each spring. Further, the community was
10 apprised of the impact that the Fort McPherson project would have on the Aklavik plant
11 rebuild schedule and cost.

12
13 The Corporation has calculated the 50% risk sharing adjustment for overheads and
14 AFUDC related to the construction delays by comparing the overheads and AFUDC
15 between the estimated original project budget - \$3.5 million estimated project cost (\$4.3
16 million with overheads and AFUDC) and the estimated revised budget submitted in the
17 Phase I GRA - \$4.4 million estimated project cost (\$5.3 million with overheads and
18 AFUDC) as illustrated in Table 1 below which will reduce the Aklavik plant addition by
19 \$27, 500.
20

**Table 1
New Modular Power Plant – Aklavik
50% Risk Sharing Adjustment**

	Original Budget Estimate	Revised GRA Rate Base Addition	Difference	50% Risk Sharing Adjustment
Overheads	421,000	457,000	36,000	18,000
AFUDC	402,000	421,000	19,000	<u>9,500</u>
				<u>27,500</u>

1 Diverting resources to the Fort McPherson plant rebuild and engaging in Aklavik
2 community consultation contributed to higher overall Aklavik plant project costs, due
3 mainly to the change in project timing and the resultant inflationary impacts, including
4 higher tender responses. Had the new Aklavik plant project proceeded on schedule, the
5 Fort McPherson plant rebuild would have taken place over a longer period of time and
6 faced the same resultant inflationary pressures as were experienced with the Aklavik
7 plant project.

8

9 The Corporation appreciates the Board's concern about the customers of Aklavik
10 bearing the entire cost of risk resulting from such delay. That result however is a
11 consequence of a community-based rate design. Since the Corporation acted prudently
12 and reasonably under the circumstances the Board's direction is not a valid precedent
13 for attributing costs to the Corporation's shareholder in future rate proceedings.
14 Nonetheless, because of the Board's expressed concern the Corporation has elected to
15 adjust overheads and AFUDC related to the Aklavik plant construction delays by 50%
16 as outlined in Table 1 above.

17

1 **Directive 3**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to exclude the capital addition**
4 **related to the plant upgrade amounting to \$900,000 from rate base additions for**
5 **Fort Liard in 2007/08.**

6

7 **Response**

8

9 The Corporation has removed the capital addition related to the Fort Liard plant upgrade
10 amounting to \$900,000 from the 2007/08 rate base. The change lowers the
11 Corporation's return on ratebase and amortization expense in the 2007/08 test year.

12

1 **Directive 4**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to provide a computation of its**
4 **cash working capital for the test years using the net lead or lag associated with**
5 **each expense item.**

6

7 **Response**

8

9 The Corporation has reflected this change in its refiling Schedules – Schedules 5.5
10 through 5.9.

11

1 **Directive 5**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to use a 6% sinking fund return**
4 **for each of the test years for purposes of calculating the effective cost of long-**
5 **term debt.**

6

7 **Response**

8

9 The Corporation has reflected this change in its refiling Schedules – Schedules 3.5 and
10 3.6.

11

1 **Directive 6**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to calculate its effective cost of**
4 **long term debt as follows:**

5

6 **Effective Cost of Long Term Debt = $(I+AFC-SFE)/(MAD-UFC-SFI)$**

7

8 **Where:**

9 **I=Interest on Mid Year Average Long Term Debt**

10 **AFC = Amortization of Financing Costs**

11 **SFE = Sinking Fund Earnings in the year based on long term average return of 6%**

12 **MAD = Mid Year Average Debt Principal**

13 **UFC = Unamortized Financing Costs**

14 **SFI = Sinking Fund Investment**

15

16 **Response**

17

18 **The Corporation has reflected this change in its refiling Schedules – Schedules 3.5 and**
19 **3.6.**

20

1 **Directive 7**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to include a capital lease rate that**
4 **reflects, for the equity portion of lease financing, the fair returns on equity of**
5 **9.00% for 2006/07 and 9.25% for 2007/08 less 25 basis points.**

6

7 **Response**

8

9 The Corporation has reflected this change in its refiling Schedules – Schedules 3.5 and
10 3.6.

11

1 **Directive 8**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to use a fair rate of return on**
4 **equity of 8.60% for 2006/07 and 9.25% for 2007/08.**

5

6 **Response**

7

8 The Corporation has reflected this change in its refiling Schedules – Schedule 3.5.

9

1 **Directive 9**

2

3 **The Board directs NTPC, in its Phase I refiling, to apply a 7% cap on losses.**

4

5 **Response**

6

7 The Corporation has reflected this change in its refiling Schedules – Schedules 2.1
8 through 2.3 and Appendix A.

9

1 **Directive 10**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to calculate forecast station**
4 **service using the same procedure used for fuel efficiencies. Forecast station**
5 **service is to be calculated using 3 years of actual data with a weighting of “3”**
6 **given to the lowest station service year, a weighting of “2” given to the middle**
7 **station service year and a weighting of “1” given to the highest station service**
8 **year.**

9

10 **Response**

11

12 The Corporation has reflected this change in its refiling Schedules – Schedules 2.1
13 through 2.3 and Appendix A. The 2006/07 forecasts reflect the weighted average station
14 service results from 2003/04; 2004/05 and 2005/06. The 2007/08 station service
15 forecasts reflect the weighted average station service results from 2004/05; 2005/06
16 and the forecast station service for 2006/07.

17

18 For Fort Resolution, Norman Wells and Fort McPherson, where the existing plants have
19 less than three years of actual operating experience, the Corporation has relied only on
20 the operating experience with the existing plants, consistent with the Board’s approval
21 for the calculation of the fuel efficiencies in those communities in Decision 13-2007.

22

1 **Directive 11**

2

3 **The Board directs NTPC, in its Phase I refiling, to apply a 5% cap on station**
4 **service as a percentage of generation.**

5

6 **Response**

7

8 The Corporation has reflected this change in its refiling Schedules – Schedules 2.1
9 through 2.3 and Appendix A.

10

1 **Directive 13**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to remove the 50% net income**
4 **component of its at-risk compensation program from the revenue requirement**
5 **calculations for NTPC's regulated business. For 2006/07, the amount is \$270,000**
6 **and, for 2007/08, the amount is \$279,000.**

7

8 **Response**

9

10 The Corporation has reflected this change in its refiling Schedules – Schedule 3.1.

11

1 **Directive 14**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to calculate its total 06/07 and**
4 **07/08 supplies and services expenses using its forecast brushing expenditures of**
5 **\$393,000 for 06/07 and \$401,000 for 07/08.**

6

7 **Response**

8

9 This directive upholds the Corporation's brushing expenditures forecasted in the
10 Application. Therefore, no change is required.

11

1 **Directive 15**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to propose a procedure for**
4 **returning to the ratepayers over a 3-year period the \$345,000 that was over-**
5 **collected by the Corporation for brushing over the 01/02 to 05/06 periods. To be**
6 **clear, the refunded \$345,000 is to be obtained from NTPC's non-regulated cash**
7 **flow, not by reducing the test year brushing expenditures.**

8

9 **Response**

10

11 The Corporation will be filing a review and variance application respecting Directives 15
12 and 45 and as such, no adjustments respecting these Directives are currently reflected
13 in the refiling.

14

1 **Directive 16**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to reconcile the 06/07 and 07/08**
4 **Bluefish supplies and services forecasts shown in Tables BR.NTPC-9 and**
5 **HC.NTPC-13(I) and described in NUL.NTPC-15(b). NTPC is to adjust the Bluefish**
6 **supplies and services forecasts as needed to account for any errors in their**
7 **information requests.**

8

9 **Response**

10

11 Please refer to Table 1 below, which is a side by side comparison of the information
12 provided by NTPC in response to BR.NTPC-9, HC.NTPC-13(I) and NUL.NTPC- 15(b)
13 concerning Bluefish supplies and services forecasts. No errors were made in
14 responding to these information requests and therefore no adjustments to the Bluefish
15 supplies and services forecasts are required.

16

Table 1
Comparison of Responses to Interogatories
Bluefish Supplies and Services Forecasts

2006/07	BR.NTPC-9	NUL.NTPC-15	HC-13
Camp Expenses	13	13	
Materials	93	92	
Allocated Insurance	96	96	
Contractors	42	42	
Water survey / hydrometric stations	10	10	
Total supplies and services costs	254	253	254
		NUL.NTPC-15	
		(Question did	
		not ask for	
		2007/08 data)	
2007/08	BR.NTPC-9	HC-13	
Camp Expenses	13		
Materials	97		
Allocated Insurance	96		
Contractors	43		
Water survey / hydrometric stations	10		
Total supplies and services costs	259		259

17

1 **Directive 17**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to provide an assessment of the**
4 **significant and growing gap between the accumulated balance in the reserve for**
5 **site restoration and the estimated site restoration costs in light of the above**
6 **discussion and propose a cap to the accumulated reserve balance until such time**
7 **as studies on the adequacy of the current balance can be completed.**

8

9 **Response**

10

11 **Background**

12

13 The liability for Future Removal and Site Restoration (FRSR) has been established for
14 two general purposes. The Future Removal component of the liability has been
15 established to fund the cost of asset removal² at the end of the asset's useful life. The
16 Site Restoration component of the liability has been established to fund the remediation
17 of sites including but not limited to costs related to soil contamination. These two
18 aspects are combined in the single FRSR maintained and reported by NTPC.

19

20 The Future Removal liability applies not only for diesel plants but also for hydro
21 facilities, transmission lines, distribution lines and the general asset category. The costs
22 summarized in Board Decision 13-2007 of \$12.9 million for "diesel plant site restoration,
23 excluding soil remediation costs" plus \$12.959 million in 2005 dollars as "the estimated
24 cost of soil decontamination" from the Biogenie study³ only address assets in FERC
25 categories 341, 342 and 343. These categories comprise only three of the six diesel-
26 related FERC categories, out of a total 45 FERC categories for depreciable plant.

² The cost is stated net of "salvage" or recoveries from the sale of scrap components. However, for the asset categories and location of NTPC's assets, these amounts are typically minimal if there is any recovery at all.

³ The costs noted by the Board in respect of the Biogenie study are in 2005 dollars. These costs will actually be incurred in future dollars (at varying times in the future depending on the site) so also require consideration of inflation to that time.

1 Consistent with the approach approved by the Board dating back to 1995/98 and
2 before, there are also substantial requirements for FRSR for hydro plant, transmission
3 lines and distribution systems.

4
5 The rates for amortization, including FRSR, were last set in the 2001/03 GRA, and
6 current rates reflect three aspects that are anticipated to potentially require adjustment
7 in the future:

8 1) The FRSR liability for hydro assets was originally recommended at 15% by
9 NTPC's depreciation consultant Gannett Fleming in 2001/03, and was lowered to
10 5% during the Negotiated Settlement for the 2001/03 GRA. This amount may
11 need to be increased in the future in order to maintain an FRSR that is in keeping
12 with NTPC's requirements and industry practice, particularly in consideration of
13 the increasing requirements under environmental regulations and land claims.

14 2) Rates prior to 2001/03 had no amount incorporated for soil remediation. The
15 2001/03 rates incorporated only \$5 million of an estimated \$16.6 million soil
16 remediation cost. In response to Directive 1 of Decision 1-2002, the Corporation
17 updated the soil remediation estimate based on more recent remediation
18 experience and estimated the cost at \$12.959 million in 2005 dollars (i.e., prior
19 to inflation).

20 3) Asset lives, particularly for diesel generation assets are expected to be lower in
21 future studies than assumed in the previous depreciation studies. In the event
22 this is confirmed in the next depreciation study, overall depreciation rates (the
23 sum of amortization of assets and FRSR) will be greater than today as the
24 amounts will need to be recovered over a shorter forecast life of assets.

25
26 It is also important to note that while the FRSR balance can be reported separately from
27 Accumulated Amortization, past practice in NWT reflects analysis of the two
28 components in combination to determine whether there are in fact "surpluses" or any
29 need to adjust, true-up, or "cap" the overall balances after any surpluses in one account,
30 are used to offset shortfalls in the other components.

1 **Recommendation**

2

3 Based on the foregoing, and in light of the fact that NTPC does not have a completed
4 updated depreciation study, NTPC does not believe that the revenue requirement for
5 the test years should be adjusted downward today to reflect any reduction in FRSR
6 appropriations. The only information available to NTPC and the Board is a preliminary
7 depreciation analysis by NTPC's depreciation experts, which suggests the overall
8 requirement for amortization of assets, may be higher than presently reflected in
9 NTPC's depreciation rates (as noted in BR.NTPC-14). At the time of the next GRA, with
10 the full information afforded by an updated deprecation study prepared by experts in this
11 area, the matter can be properly considered. In the meantime, customers are not being
12 prejudiced by any delay in this area, as in the unlikely event the next GRA concludes
13 that there is excess total Accumulated Amortization, this excess will be available to
14 benefit the customer through lower rates at that time.

15

16 With respect to whether there should be a "cap" in place that would terminate new
17 appropriations to the reserve in future should the FRSR exceed some pre-defined
18 balance, NTPC does not recommend this approach. The current approach is based on
19 the best available evidence from experts in the field.

20

1 **Directive 18**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to file a written policy with**
4 **regards to the criteria that are to be used to determine the eligibility of**
5 **expenditures for deferral account treatment.**

6

7 **Response**

8 In the Board's discussion around this Directive, the terms deferral account and deferred
9 costs are being used to discuss the job evaluation costs. As discussed by the NTPC
10 witnesses at page 139-140 of the transcript, these are two different treatments:

11

12 - **Deferral accounts** are regulatory accounts for costs that occur each year but
13 where the amount of the expenditures may fluctuate significantly from one year
14 to the next. The purpose of deferral accounts is to protect Customers and the
15 Corporation from the impact of hard to predict or costs that occur sporadically
16 and smooth out rates set to recover these costs from year to year. Actual costs
17 spent on the particular expenditure in a given year are charged to the deferral
18 account and the account is drawn down on an annual basis by a normalized
19 amount set out by the Board. The annual normalized amount set by the Board is
20 set with the intention to "zero out" the deferral account over a given number of
21 years based on the estimated annual expenditures added to the account over
22 this period of time. Examples of deferral accounts currently in place include the
23 overhaul deferral account, the PUB regulatory costs deferral account, and the
24 Reserve for Injuries and Damages account.

25 - **Deferred costs** are costs incurred for intangible assets, generally incurred over a
26 short period of time, that create a long-term or enduring benefit to Customers.
27 They are similar to fixed costs with the exception of their intangible nature.
28 Deferred costs are not expected to occur annually, they generally occur once in a
29 very broad period of time if they are ever repeated at all (i.e., some are purely
30 one-time costs) as described at pages 16-19 of the Corporation's final argument.

1 Historically, the Board has generally accepted treatment of costs that are
2 significant from a rate impact point of view and where the corresponding benefits
3 are spread over a number of years, as deferred costs for regulatory purpose.
4 Examples of deferred costs put in place in the past include debt financing costs,
5 depreciation studies, and the job evaluation study.

6
7 **Proposed Policy**

8 Policy: To determine the accounting treatment for deferred costs and deferral accounts.

9
10 Deferral accounts:

11 The purpose of deferral accounts is to protect the Customer and the Corporation from
12 the impact of hard to predict or costs that occur sporadically and to smooth out rates
13 related to costs for a particular expenditure incurred on an annual basis but where the
14 amount of the expenditures may fluctuate significantly from one year to the next.

15
16 The establishment of deferral accounts and deferral account mechanism must be
17 approved by the PUB before implementation.

18
19 Deferred costs:

20 Deferred costs are costs incurred over a short period of time – one or two years, where
21 this expenditure would be significant from a rate impact point of view and where the
22 corresponding benefits are spread over a number of years either via increased future
23 revenues or reduced future expenditures. Deferred costs are not expected to occur
24 annually; they are either one-time costs or occur once in a very broad period of time
25 (e.g., depreciation studies).

26
27 Where the Corporation makes expenditure and determines that expenditure results in
28 an intangible asset (no physical asset results) that benefits more than one year, the
29 Corporation will defer and amortize these costs. Appropriate deferred costs will have to
30 meet these tests:

- 1 1. there is a benefit to the Customer of more than one year
- 2 2. the expenditure is not covered in the Corporation's current revenue requirement

3

4 Deferred costs will be amortized over a 5-year period or a more applicable term if one
5 can be demonstrated by applying a matching test of benefit duration to amortization
6 period.

7

8 Qualifying deferred costs will be presented as regulatory assets on the Corporation's
9 balance sheet.

10

1 **Directive 19**

2

3 **The Board directs NTPC, in its Phase I refilling, to adjust the test year sales**
4 **forecasts by community having regard to historical normalized average use per**
5 **Customer and any other relevant factors considered in the top down and bottom**
6 **up approaches. NTPC is to reflect in the refiling any consequential impacts of any**
7 **changes in sales forecasts on fuel costs and any other second order impacts.**

8

9 **Response**

10

11 The Corporation has considered historical normalized average use per Customer,
12 among other methods, in reviewing its sales forecast for Residential and General
13 Service Customers by community. The review of the average use per Customer method
14 indicates that on the whole, the Corporation's test year forecasts for Residential sales
15 are reasonable with only three communities outside of an 8% tolerance. For General
16 Service, the Corporation maintains that for reasons discussed below, the average use
17 per Customer method is not a good measure of forecast accuracy. The Corporation's
18 refilling therefore does not reflect any adjustment to the forecast sales for Residential or
19 General Service Customers.

20

21 Load forecasting is a difficult exercise that must consider the influences of a number of
22 different factors, only one of which is weather. The last time the Corporation reviewed
23 its load forecast method in detail, it was a significant undertaking. The average use per
24 Customer method was raised late in the Phase I proceeding and has not been
25 subjected to the degree of testing as the Corporation's current method. As well, the
26 average use per Customer illustration provide by HC in relation to Fort Smith failed to
27 consider the most recent year of data and was based on a simple average which may or
28 may not be the most appropriate indication of trend in Customer usage and usage
29 patterns.

1 The Corporation agrees with the Board that average use per Customer can be a helpful
2 test of reasonableness for Residential sales forecasts. The Corporation undertook a
3 comparison of the most recent 4-year simple average use per Customer by community
4 for Residential Customers. Corporation wide, the average use per Customer measure
5 produced similar results to the Corporation's existing method (5% variance at the
6 Customer class level). On a Community by Community basis, only three communities in
7 each test year had variance between the two methods of more than plus or minus 8 per
8 cent. In consideration of the small numbers of Customers in many of these communities
9 and the impact that one household can have on the Residential sales within a
10 community, the Corporation considers that its method performed well within a degree of
11 reasonableness compared to the simple average use per Customer method. In addition,
12 as indicated in Undertaking 14 (exhibit 32), across the thermal communities the
13 Corporation's current load forecast method gave rise to forecasts that were very
14 consistent with 2006/07 preliminary actuals.

15
16 Should the Board decide that the sales forecast should be adjusted to bring the three
17 communities within an eight per cent tolerance of the most recent four-year simple
18 average use per Customer, the impact on the Corporation's Application would be small.
19 For future GRA's the Corporation will incorporate an average use per Customer test of
20 reasonableness in Residential sales forecasts after considering the term (number of
21 years of data) and average method (e.g. weighted vs simple) and other factors that
22 might influence the reliability of this method as a test of forecasting accuracy.

23
24 With respect to General Service Customers, the Corporation notes that based on a
25 preliminary review of this issue, it would expect that the average use per Customer
26 method would be much less appropriate for General Service Customers than for
27 Residential Customer for the following reasons:

28

- 1 • Residential Customers tend to be more homogeneous than General Service
2 Customers. There is a smaller range of consumption levels for Residential
3 Customers than General Service Customers.
- 4 • There tend to be more Residential Customers in a community than General
5 Service Customers; therefore changes in the load patterns of one General
6 Service Customer will have a much greater impact on the class average.

7

8 Further, while the Corporation has not had the time to do a complete survey of load
9 forecast methodologies used by other utilities, some utilities that use an average use
10 per Customer approach for Residential Customers use a different approach for General
11 Service or Commercial Customers.⁴ Prior to considering whether an average use per
12 Customer is an appropriate method or an appropriate test of reasonableness for the
13 General Service Customer sales forecast, the Corporation would need to consider the
14 following:

- 15
- 16 • Diversity of load patterns among General Service Customers;
- 17 • Relative influence on General Service Customers of weather compared to other
18 factors;
- 19 • Historical performance of regression based forecast methods compared to
20 average use per Customer methods;

21

22 The Corporation feels that there is enough uncertainty with respect to the relevance of
23 an average use per Customer method for General Service Customers that such an
24 approach cannot be considered to be meaningful either as a forecasting method or as a
25 test of the current forecast without considerable additional investigation. The
26 Corporation cannot complete such an investigation during the refiling period.

⁴ Manitoba Hydro for example uses a forecasting method for Residential Customer based on an average use per Customer type of approach. However for General Service Customers, Manitoba Hydro reviews its Top Consumer forecasts individually and uses a regression analysis for other General Service Customers.

**Directive Response
PUB Decision 13-2007
NTPC GRA 2006/07 and 2007/08
October 1, 2007**

1 Therefore, in the Corporation's view, there should be a degree of caution in adjusting its
2 sales forecast to take account of the average use per Customer method with which the
3 Corporation and the Board have limited experience and have not had the opportunity to
4 test in detail. The Corporation notes, for example, that there could be numerous ways to
5 develop an average use per Customer, each with its own risks and potential benefits.
6 The competing influences of weather and uptake of more energy efficient technologies
7 would need to be considered, as well as instances where population and Customer
8 counts are declining but gross electricity sales are increasing. The Corporation simply
9 has not had the time or resources available during the refiling period to investigate
10 these issues.

11

1 **Directive 20**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to reflect the revised forecast of**
4 **miscellaneous revenues.**

5

6 **Response**

7

8 The Corporation has reviewed this directive and has the following discussion. HC's
9 Argument (p. 14) submits that contract revenues should be increased by \$45,000 and
10 the connection charge revenues be increased by \$30,000 for a total of \$75,000 in each
11 of the two test years. NTPC accepted this methodology in its Reply Argument (p. 32)
12 however the reported forecast for miscellaneous revenues of \$817,000 for 2007/08 was
13 incorrect. NTPC notes the 2007/08 forecast should be \$862,000, which is the sum of
14 \$787,000 (original 2007/08 miscellaneous forecast from GRA) plus \$75,000 as noted
15 above.

16

17 Consequently, the Corporation has reflected the revised forecast for miscellaneous
18 revenues of \$914,000 for 2006/07 and \$862,000 for 2007/08. These changes are
19 reflected in non-utility revenues in Schedule 4.1.

20

1 **Directive 21**

2

3 **The Board directs NTPC, in its Phase 1 refiling, to propose a cost effective**
4 **approach to excluding the costs and risks associated with generation and**
5 **transmission outages from the Snare-Yellowknife water stabilization fund, having**
6 **regard to the administrative costs involved, and to reflect these proposals, in the**
7 **refiling.**

8

9 **Response**

10

11 The Corporation has reviewed methods for adjusting the water stabilization fund to
12 remove the impact of generation and transmission outages. It is important to note that
13 the current method is based on actual diesel and hydro generation, variables that are
14 easily measured and tested, and is therefore simple and transparent in its operation.
15 The removal of diesel fuel expense from the water stabilization fund will require that this
16 expense be forecast and included in the Corporation's revenue requirement. This will
17 both increase the Corporation's forecasting risk and require the application of judgment
18 as to where diesel fuel expense should be charged when these events occur.

19

20 In order to reply to the Board's directive, the Corporation considered three types of
21 generation and transmission outages it would need to address:

22

- 23 • Forced outages due to unexpected or unplanned events;
- 24 • Outages related to capital projects; and
- 25 • Regularly planned maintenance outages.

26

27 Proposed treatment for each of these types of outages are described in further detail
28 below.

29

1 **Forced Outages**

2

3 Forced outages include unplanned or unexpected outages. These outages are difficult
4 to predict and occur irregularly. The Corporation has Forced Outage Rates (“FOR”)
5 approved for planning purposes by the Board as part of the Required Firm Capacity
6 (“RFC”) proceeding. Given that these FOR have been reviewed and tested by the Board
7 and other interested parties, the Corporation proposes to use the FOR to estimate the
8 average diesel requirements for the Snare Yellowknife System due to forced outages.
9 The calculation of these diesel requirements is shown in Table 1. It is important to note
10 that these reflect averages for planning purposes. Actual results will vary each year.

11

12 **Table 1. Calculation of Diesel Fuel Requirements for Forced Outages**

	2006/07	2007/08
1 Hydro Unit Forced Outage Rate	1.4%	1.4%
2 Total Forecast Hydro Generation (GW.h)	190.7	194.0
3 Forecast Diesel Required for Hydro Unit Outages(GW.h)	2.67	2.72
4 L-199 Transmission Line Forced Outage Rate	0.1435%	0.1435%
5 Forecast Snare Generation (GW.h)	153.9	156.5
6 Forecast Diesel Required for L-199 Outages (GW.h)	0.22	0.22
7 Bluefish Transmission Line Forced Outage Rate	0.2100%	0.2100%
8 Forecast Bluefish Generation (GW.h)	36.8	37.5
9 Forecast Diesel Required for Bluefish Transmission Outages (GW.h)	0.08	0.08
10 Total Forecast Diesel Required for Forced Outages (GW.h)	2.97	3.02

13

14

15 The Corporation would require on average, 2.97 GW.h of additional diesel generation in
16 2006/07 and 3.02 GW.h of additional diesel generation in 2007/08 based on the
17 forecast hydro generation to be utilized. This is the simplest method the Corporation
18 could develop in the time available that would be suitable to apply and test in future
19 General Rate Applications.

20

1 **Outages Related to Hydro-Electric and Transmission Capital Projects**

2

3 Outages will also occur as a result of capital projects related to the hydro-electric
4 generation and transmission assets additions and upgrades. Consistent with normal
5 accounting practice, the Corporation will recover diesel fuel consumed due to capital
6 projects as part of the project costs on an individual project by project basis and not
7 through test year fuel expenses or the water stabilization fund.

8

9 **Outages Related to Hydro-electric and Transmission Planned Maintenance**

10

11 Outages also occur due to regularly planned maintenance of hydro units and
12 transmission assets. The Corporation plans maintenance on the 5 hydro units on the
13 system one at a time and to take place during periods of low generation requirements
14 so that there is no additional diesel generation is required. In the event the Corporation
15 incurs diesel expense during planned hydro maintenance the water stabilization fund
16 will not be used.

17

18 The transmission line and substations require 3 days of maintenance during the year,
19 which require the shut down of the hydro generation. This maintenance will be planned
20 during periods of low generation and coordinated with the exercising of the diesel
21 engines so that there is no additional diesel generation is required. In the event the
22 Corporation incurs diesel expense during planned transmission line and substation
23 maintenance the water stabilization fund will not be used.

24

25 **Resulting Changes to Fuel Expense**

26

27 Based on this review, the Corporation has reflected the following adjustments to its
28 diesel fuel forecasts for the Snare/Yellowknife system in its refiling schedules:

29

- 1 • Adding 2.97 GW.h of diesel generation in 2006/07 and 3.02 GW.h of diesel
2 generation in 2007/08 in recognition of an allowance for Forced Outage.
- 3 • Removing from the 2006/07 forecast amounts related to outages.

4

5 The Corporation has retained an amount of diesel generation for exercising and peaking
6 requirements. As this generation is not related to outages, it will continue to be
7 recovered via the water stabilization fund. This results in revised forecast diesel
8 generation on the Snare system of 4.237 GW.h in 2006/07 and 4.398 GW.h in 2007/08.

9 With respect to the operation of the Snare/Yellowknife water stabilization fund, the
10 Corporation proposes to add a line that would reduce the actual diesel generation to
11 remove diesel fuel burned as a result of an outage. This is illustrated in Table 2 below.

12 Pursuant to the Board's directive, only diesel generation related to outages would be
13 removed (i.e. diesel generation as a result of peaking or exercising requirements would
14 continue to be charged to the water stabilization fund). Therefore the Corporation has
15 reflected a transfer to the water stabilization fund for diesel fuel expense related to
16 peaking and exercising in Schedule 3.1 of the refiling.

17

1 **Table 2. Illustrative Example of Proposed Calculation**
2 **of the Snare-Yellowknife Water Stabilization Fund**
3

1	Hydro Generation In Rates (kW.h)	220,000,000
2	Actual Hydro Generation (kW.h)	215,000,000
3	Generation Required (Saved)	5,000,000
4	Transmission Line Losses (L3 x 4%)	<u>(200,000)</u>
5	A - Diesel Gen. Req'd (Saved) (L3+L4)	4,800,000
6	B - Actual Diesel Generation (kW.h)	3,500,000
7	Lessor of A or B	3,500,000
8	Less Diesel Due to Outages (kW.h)	1,000,000
9	Adjusted Diesel Generation (kW.h)	2,500,000
10	Plant Efficiency(KWH/L) PUB Approved	<u>3.500</u>
11	Litres of Fuel Required (L9/L10)	714,000
12	PUB Approved Fuel Price \$	0.7000
13	Additional (Less) Diesel Cost \$ (L11 x L12)	\$500,000 =====
14	Water Stabilization Fund Continuity (\$)	
15	Opening Deficiency (Surplus)	0
16	Refund/ (Collection) Rider	
17	Additional (Less) Diesel Cost (L13)	500,000
18	Closing Balance Before Interest	500,000
19	Interest Rate (Prime less 50 points)	4.50%
20	Interest Charged (Earned)	2,000
21	Closing Deficiency (Surplus)	\$502,000 =====

4
5 As there is no active water stabilization fund for the Taltson system, the Corporation has
6 retained all diesel fuel expenses for Taltson as part of the Corporation's revenue
7 requirement.
8

1 **Directive 22**

2

3 **The Board notes NTPC’s concern respecting material costs for maintaining**
4 **separate fuel stabilization accounts by community. However, the Board considers**
5 **the premise of community based rates can be maintained if the change in fuel**
6 **cost following a change in the reference price of oil can result in different riders**
7 **for each community based on the forecast efficiencies and station service/losses**
8 **for that community. Since the change in the fuel cost on a per kWh basis could be**
9 **expected to be approximately the same for all communities, there will be no**
10 **requirement to maintain separate fuel stabilization accounts by community. The**
11 **reconciliation of revenues and costs recorded in the fuel stabilization account**
12 **could be carried out as at present using a single fund. The Board directs NTPC to**
13 **consider these comments and propose a procedure for determining future fuel**
14 **stabilization riders triggered by fuel price changes as part of the refilling.**

15

16 **Response**

17

18 The Corporation has reviewed the Board’s directive and comments in Decision 13-2007.
19 In the Corporation’s view, the most practical way to implement the recommendation of
20 the Board is to develop a community specific index for the fuel rider that recognizes
21 differences in fuel efficiency, line losses and station service. Table 1 below shows the
22 calculation of the fuel rider index for 2006/07. Table 2 shows the calculation of the fuel
23 rider index for 2007/08.

24

25 Column A shows the fuel efficiency for each community. Column B shows the line
26 losses as a per cent of generation. Column C shows the station service as a per cent of
27 generation. Column D calculates the litres of fuel required per kW.h of sales using the
28 formula $1 / (\text{fuel efficiency} / (1 - \text{“line loss percentage”} - \text{“station service” percentage}))$.
29 The same figure can be obtained by taking the litres of fuel required (shown on the
30 Schedules in Appendix A) divided by the total sales (also shown on each Schedule in

1 Appendix A). Column E indexes the litres of fuel required in each community to the
2 lowest value in the sample set (in this case Fort Simpson).

3
4 NTPC proposes to calculate the base fuel rider in exactly the same manner as is done
5 currently. The base fuel rider would then be multiplied by the Fuel Rider Index in
6 Column E to calculate the community specific fuel rider. Actual rider revenues would
7 continue to be credited against the balance in the fuel stabilization fund.

8

9

Table 1. Calculation of 2006/07 Community Fuel Rider Index

PLANT		GRA Fuel Efficiency	GRA Line Losses	GRA Station Service	Litres Fuel Required	
NO.	PLANT	(kW.h/l)	(per cent of generation)	(per cent of generation)	per kW.h Sales	Indexed
104	Wha Ti	3.711	7.0%	1.4%	0.294	1.009
105	Rae Lakes	3.398	4.5%	5.0%	0.325	1.116
110	Lutsel K'e	3.778	5.7%	5.0%	0.296	1.017
305	Tuktoyaktuk	3.697	7.0%	4.5%	0.305	1.048
306	Fort McPherson	3.609	4.2%	4.4%	0.303	1.041
307	Aklavik	3.475	5.7%	3.6%	0.317	1.089
308	Deline	3.546	7.0%	2.2%	0.310	1.066
309	Fort Good Hope	3.576	5.3%	3.5%	0.307	1.053
310	Tulita	3.634	7.0%	5.0%	0.313	1.073
311	Paulatuk	3.492	7.0%	4.0%	0.322	1.103
312	Sachs Harbour	3.189	4.8%	5.0%	0.348	1.193
313	Tssigehtchic	3.537	6.6%	5.0%	0.320	1.097
314	Colville Lake	2.957	7.0%	1.2%	0.368	1.264
315	Holman	3.616	5.5%	3.4%	0.304	1.042
205	Fort Simpson	3.755	5.5%	3.1%	0.291	1.000
206	Fort Liard	3.725	7.0%	1.4%	0.293	1.006
207	Wrigley	3.525	6.2%	3.5%	0.314	1.078
208	Nahanni Butte	2.511	7.0%	5.0%	0.452	1.552
209	Jean Marie River	2.749	7.0%	5.0%	0.413	1.419

10

11

1

Table 2. Calculation of 2007/08 Community Fuel Rider Index

PLANT		A	B	C	D	E
		GRA Fuel	GRA Line	GRA Station	Litres	
		Efficiency	Losses	Service	Fuel	
		(kW.h/l)	(per cent of	(per cent of	Required	
NO.	PLANT		generation)	generation)	per kW.h	Indexed
					Sales	
104	Wha Ti	3.711	7.0%	1.3%	0.294	1.010
105	Rae Lakes	3.398	4.5%	5.0%	0.325	1.118
110	Lutsel K'e	3.778	5.7%	5.0%	0.296	1.018
305	Tuktoyaktuk	3.697	7.0%	4.6%	0.306	1.051
306	Fort McPherson	3.609	4.2%	4.5%	0.303	1.043
307	Aklavik	3.475	5.7%	4.0%	0.319	1.095
308	Deline	3.546	7.0%	2.2%	0.310	1.067
309	Fort Good Hope	3.576	5.3%	3.2%	0.306	1.051
310	Tulita	3.634	7.0%	5.0%	0.313	1.075
311	Paulatuk	3.492	7.0%	3.8%	0.321	1.104
312	Sachs Harbour	3.189	4.8%	5.0%	0.348	1.195
313	Tssigehtchic	3.537	6.6%	4.7%	0.319	1.096
314	Colville Lake	2.957	7.0%	1.0%	0.367	1.263
315	Holman	3.616	5.5%	3.2%	0.303	1.041
205	Fort Simpson	3.755	5.5%	3.0%	0.291	1.000
206	Fort Liard	3.725	7.0%	1.4%	0.293	1.007
207	Wrigley	3.525	6.2%	3.7%	0.315	1.083
208	Nahanni Butte	2.511	7.0%	5.0%	0.453	1.556
209	Jean Marie River	2.749	7.0%	5.0%	0.413	1.421

2