

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 Public Utilities Board Decision 13-2007 dated August 29, 2007;

AND IN THE MATTER OF the Northwest Territories Power Corporation's 2006/07 and 2007/08 Phase I General Rate Application Refiling Pursuant to Decision 13-2007.

**PHASE I REILING ARGUMENT OF
THE NORTHWEST TERRITORIES POWER
CORPORATION**

October 23, 2007

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1 **1. Introduction**

2 On August 29, 2007 the Northwest Territories Public Utilities Board (the “Board” or “PUB”)
3 issued its Decision 13-2007 in respect of the Northwest Territories Power Corporation (the
4 “Corporation” or “NTPC”) 2006/08 Phase I General Rate Application (the “Application”).
5 Decision 13-2007 set out a number of directions or directives to the Corporation, 22 of which
6 required a Phase I Refiling by the Corporation in order for the Board to finalize its decision on
7 the Application.

8 The Corporation filed its Phase I Refiling addressing Directive Nos. 1 to 11, 13, 14 and 16 to 22
9 on October 1, 2007, and its response to Directive No. 12 on October 5, 2007 (collectively the
10 “Refiling”). Directive 15 was not responded to as NTPC will be filing a review and variance
11 application concerning this directive.

12 On October 9, 2007 the Board, the City of Yellowknife and the Towns of Hay River and Fort
13 Smith (collectively the “Hydro Communities” or “HC”) and the communities of Fort Liard, Fort
14 Simpson and Inuvik (collectively the “Thermal Generation Communities” or “TGC”) filed and
15 served information requests on NTPC relating to the Refiling. The Corporation responded to
16 those information requests on October 16 and 18, 2007 (the “Refiling IRs”).

17 **2. Requested Relief**

18 For the reasons discussed in this Argument, the Corporation respectfully requests the Board to
19 issue the following Order or Orders:

- 20 i. declaring that the Corporation has fully complied with Directive Nos. 1 to 4, 6 to
21 14, 16, 18 and 20;
- 22 ii. clarifying whether Directive No. 5 requires that a 6% rate for sinking fund
23 earnings applies only to funds in non-immunized portfolios (with immunized
24 portions of the portfolio reflecting the fixed returns known to be achieved by
25 investments of these characteristics during the test years), or alternatively
26 declaring that the Corporation has fully complied with Directive No. 5;
- 27 iii. declaring that the applied for FSFR (defined below) appropriations are reasonable
28 and will be approved, that no cap to FRSR appropriations is required at this time
29 and that the Corporation has fully complied with Directive No. 17;
- 30 iv. approving the Deferred Cost Policy set out in response to Directive No. 18;
- 31 v. declaring that the applied for residential and general service sales forecasts are
32 reasonable and will be approved, and that the Corporation has fully complied with
33 Directive No. 19;
- 34 vi. clarifying whether Directive No. 21 should be implemented and declaring that the
35 Corporation has fully complied with Directive No. 21; and
- 36 vii. setting out a final Phase I decision and direction to the Corporation to file final
37 GRA schedules consistent with the Board’s decision.

1 **3. Directive Nos. 1 to 4, 6 to 14, 16, 18 and 20**

2 The Refiling provided complete responses to the Directive Nos. 1 to 4, 6 to 14, 16, 18 and 20.
 3 The following table summarizes the changes to the Corporation's original GRA filing and the
 4 corresponding Refiling revised schedules impacted by such changes for each of those Directive
 5 responses.

Directive No.	Impact of Phase I Refiling	Phase I Refiling Revised Schedules Oct 1 2007
1	<p>Reduced net addition to ratebase related to the Fort McPherson plant rebuild in 2004/05 by \$193,000.</p> <p>Added a \$193,000 charge to the RFID in 2004/05; reflected in the Corporation's capitalization as a decrease in no-cost capital. Adjusted return on rate base to reflect this correction.</p> <p>Reduced amortization expense by approximately \$7,000 in 2006/07 and 2007/08.</p>	Schedule 3.6, Schedule 5.1 and 5.2, Appendix C.
2	Reduced the Aklavik plant addition to ratebase by \$27,500 related to the additional costs in AFUDC and overheads due to the project delays as a result of additional community consultation and the temporary redeployment of engineering staff to the Fort McPherson plant fire.	Schedule 5.1 and 5.2; Appendix C.
3	Removed the capital addition related to the Fort Liard plant upgrade amounting to \$900,000 from the 2007/08 rate base. Lowered return on ratebase and amortization expense in the 2007/08 test year.	Schedule 5.1 and 5.2; Appendix C.
4	Revised cash working capital for the test years using the net lead or lag associated with each expense item.	Schedules 5.5 to 5.9.
6	<p>Calculated effective cost of long term debt as follows:</p> $\text{Effective Cost of Long Term Debt} = (I + AFC - SFE) / (MAD - UFC - SFI)$ <p>Where:</p> <p>I = Interest on Mid Year Average Long Term Debt</p> <p>AFC = Amortization of Financing Costs</p> <p>SFE = Sinking Fund Earnings in the year based on long term average return of 6%</p> <p>MAD = Mid Year Average Debt Principal</p> <p>UFC = Unamortized Financing Costs</p> <p>SFI = Sinking Fund Investment</p>	Schedules 3.5 and 3.6.
7	Included a capital lease rate that reflects, for the equity	Schedules 3.5 and

Directive No.	Impact of Phase I Refiling	Phase I Refiling Revised Schedules Oct 1 2007
	portion of lease financing, the fair returns on equity of 9.00% for 2006/07 and 9.25% for 2007/08 less 25 basis points.	3.6.
8	Use a fair rate of return on equity of 8.60% for 2006/07 and 9.25% for 2007/08.	Schedule 3.5.
9	Applied a 7% cap on losses.	Schedules 2.1 to 2.3 and Appendix A.
10	<p>Calculated forecast station service using 3 years of actual data with a weighting of “3” given to the lowest station service year, a weighting of “2” given to the middle station service year and a weighting of “1” given to the highest station service year.</p> <p>For Fort Resolution, Norman Wells and Fort McPherson, where the existing plants have less than three years of actual operating experience, the Corporation has relied only on the operating experience with the existing plants.</p>	Schedules 2.1 to 2.3 and Appendix A.
11	Applied a 5% cap on station service as a percentage of generation.	Schedules 2.1 to 2.3 and Appendix A.
12	No change required as the result of further analysing the costs and benefits of Automatic Meter Reading projects.	
13	Removed the 50% net income component of the at-risk compensation program from the revenue requirement calculations for NTPC’s regulated business. For 2006/07, the amount is \$270,000 and, for 2007/08, the amount is \$279,000.	Schedule 3.1.
14	No change required to calculate its total 06/07 and 07/08 supplies and services expenses using its forecast brushing expenditures of \$393,000 for 06/07 and \$401,000 for 07/08.	
16	No change required to the Bluefish supplies and services forecasts as the result of reconciling the 06/07 and 07/08 Bluefish supplies and services forecasts shown in Tables BR.NTPC-9 and 5 HC.NTPC-13(l) and described in NUL.NTPC-15(b) because no errors were made.	
18	See the response to Directive No. 18 for the full text of the proposed policy to determine the accounting treatment for deferred costs and deferral accounts	
20	Revised forecast for miscellaneous revenues of \$914,000 for 2006/07 and \$862,000 for 2007/08.	Table 4.1.

1 Accordingly, the Corporation respectfully requests the Board to declare that the Corporation has
2 fully complied with Directive Nos. 1 to 4, 6 to 14, 16, 18 and 20.

3 **4. Directive No. 5 – Sinking Fund Earnings**

4 The Refiling reflects the Board’s Directive No. 5 in regards to sinking fund earnings estimates, at
5 6% per annum, for *all* funds invested in sinking funds. Notwithstanding this aspect of the
6 Refiling, NTPC remains unclear as to the exact intent of the Board’s Directive and requests the
7 Board’s clarification as to whether the 6% rate is meant only to apply to funds in non-immunized
8 portfolios (with immunized portions of the portfolio reflecting the fixed returns known to be
9 achieved by investments of these characteristics during the test years). The difference is material
10 to the final revenue requirement (approximately \$400,000) and merits clarification from the
11 Board.

12 Directive No. 5, as applied by NTPC in the Refiling, is unclear as it fails to reflect the need for
13 NTPC to make prudent investment management decisions commensurate with the time to
14 maturity of its investments. A prudent approach to management of sinking funds recognizes that
15 there is a portion of the sinking funds that has been “immunized” into safe investments in the
16 2006/08 test years in recognition of the very short time to maturity of those funds.

17 For example, as of the 1995/98 GRA, the funds invested in sinking funds, on average, were not
18 expected to be required for approximately 14 years into the future. As of the 2001/02 GRA, the
19 average weighted time to maturity of the investments in the sinking fund was approximately 9
20 years. In this GRA, the average time to maturity of these investments, when the funds would be
21 needed to pay off the underlying debt, is approximately 4 years and declining.¹ Consistent with
22 the investment parameters used by any prudent investor – be it a corporation planning for
23 retirement of sinking fund debt or an individual planning for personal retirement – when the
24 funds in the underlying investments will be required in a very short period of time (e.g., the 4
25 year horizon in this GRA) the prudent range of investments are not the same as when that
26 horizon is 9 years or more. The prudent range of investments for an account with a shorter time
27 until the funds are required will be focused far more on investments that are unlikely to decline
28 in value but are also not likely to produce the same average earnings, such as short-term
29 government or corporate bonds, in comparison to stocks which can decline in value for
30 considerable periods of time.

31 For non-immunized funds invested over the long-term in investments appropriate for a sinking
32 fund, including no more than 25% in equities consistent with NTPC’s policy provided in
33 HC.NTPC-23(d),² the Board’s directed 6% return is not outside the range of reasonableness.
34 This is within the range consistent with the NTPC policy in that it is approximately 4% above
35 core inflation and approximately 2% above the present yield on long Canada benchmark bonds
36 (presently approximately 4%). However, for an immunized portfolio of funds that will be
37 required to be redeemed in less than 24-36 months, chasing returns in this range is simply
38 imprudent. While the Board’s determination of a 6% return is based on actual returns realized in
39 recent years, those returns were earned in years when the average time to maturity of the
40 underlying investments was still in a range such that a broader range of investments for the entire

¹ Refiling IRs, HC.NTPC-1(b) and attached Schedules.

² Ex. 7.

1 portfolio was prudent (the 2003 to 2006 actual returns cited by the Board were during a period
2 averaging 7 years or more to maturity for the underlying funds³ – far above the present situation)
3 and during a period when NTPC had no funds immunized.

4 Directive No. 5, as it is presently worded and interpreted by NTPC, puts pressure on the
5 Corporation to be required to chase returns beyond the risk-tolerance level it should prudently
6 adopt, or alternatively be required to accept sinking fund returns below the level incorporated in
7 NTPC's rates, and as a result be unable to fairly achieve its target return on equity for the test
8 years. Either outcome would be inconsistent with the Board's normal approach to regulation.

9 The alternative interpretation of the Board's Decision is that the long-term average approach
10 requires application of the 6% average earnings to only non-immunized funds in each test year.
11 Any immunized portion of the sinking fund portfolio (that is required very soon, such as within
12 36 months, and consequently invested in short-term safer instruments) would reflect the known
13 returns for this type of investment (such as the short-term Canada bond yields over 1-3 years;
14 approximately 4%).

15 The Corporation submits that this alternative interpretation of the Board's methodology is fair
16 and reasonable, and consistent with prudent portfolio management theory. In addition, this
17 approach will allow for a standard methodology to be applied in future hearings, regardless of
18 the overall average time to maturity, without prejudicing the Corporation or its customers as to
19 the prudent management of the sinking fund portfolio.

20 **5. Directive No. 17 – Future Removal and Site Restoration**

21 In Directive No. 17, which addresses the reserve for future removal and site restoration
22 (“FRSR”), the Board directed the Corporation to:

23 ...provide, as part of the refiling, an assessment of the significant and growing
24 gap between the accumulated balance in the reserve for site restoration and the
25 estimated site restoration costs in light of the above discussion and propose a cap
26 to the accumulated reserve balance until such time as studies on the adequacy of
27 the current balance can be completed.⁴

28 It appears that the Board may have concluded there is “significant and growing gap between the
29 accumulated balance in the reserve for site restoration and the estimated site restoration costs”
30 based on a comparison of the FRSR reserve 2004/05 fiscal year end balance of \$37.154 million
31 versus \$12.9 million for diesel plant site restoration costs plus \$12.959 million (2005 dollars) for
32 diesel site soil decontamination costs.⁵ If that is the case, with respect, the conclusion is not
33 correct.

34 While the FRSR reserve 2004/05 fiscal year end balance is in fact \$37.154 million, only \$12.156
35 of that total amount is attributable to diesel plants. Further, both costs to remove the assets and
36 reclaim the lands (which includes soil remediation) must be eventually paid for out of FRSR

³ Decision 13-2007 at 24.

⁴ Decision 13-2007 at 120.

⁵ Decision 13-2007 at 119.

1 reserve. Consequently, if one were to consider diesel plant future removals and site restoration
2 alone, the comparison based on available data would be to contrast the \$12.156 million set aside
3 to the end of 2004/05 for diesel plant site restoration costs, against the now dated \$12.9 million
4 estimate (in 2001/03 GRA dollars) for above ground restoration plus \$12.959 million (2005
5 dollars) for diesel site soil decontamination costs. In short, even using dated numbers based on a
6 smaller plant in service (since 2001/03 there has been material diesel plant additions) and
7 ignoring inflation over this period, the total future requirement for diesel is at least approaching
8 \$26 million compared to only the \$12.156 million set aside, resulting in a shortfall of over \$13
9 million in the FRSR reserve attributable to diesel plants alone.

10 It is important to recall that the FRSR reserve applies to more than just diesel plant sites and that
11 the above noted comparison comprises only three of the six diesel related FERC categories, out
12 of a total 45 FERC categories for depreciable plant.⁶ Consequently, in assessing the sufficiency
13 of the FRSR reserve, one must also consider the future requirements for hydro facilities,
14 transmission lines, distribution lines and the general asset category. As noted in the
15 Corporation's response to Refiling IRs HC.NTPC-3, the FRSR reserve 2004/05 fiscal year end
16 balance of \$37.154 million includes \$6.164 million for hydro plant, \$13.125 million for
17 transmission plant, \$5.654 million for distribution plant and \$0.055 million for general plant, in
18 addition to the \$12.156 million for diesel plant.

19 It is also important to recall that the current figures require updating before assessing the
20 sufficiency of the FRSR reserve. As noted in the Corporation's response to Directive No. 17, the
21 following three adjustments are anticipated to potentially require adjustment in the next
22 depreciation study:

- 23 1) The FRSR liability for hydro assets was originally recommended at 15%
24 by NTPC's depreciation consultant Gannett Fleming in 2001/03, and was
25 lowered to 5% during the Negotiated Settlement for the 2001/03 GRA.
26 This amount may need to be increased in the future in order to maintain an
27 FRSR that is in keeping with NTPC's requirements and industry practice,
28 particularly in consideration of the increasing requirements under
29 environmental regulations and land claims.
- 30 2) Rates prior to 2001/03 had no amount incorporated for soil remediation.
31 The 2001/03 rates incorporated only \$5 million of an estimated \$16.6
32 million soil remediation cost. In response to Directive 1 of Decision 1-
33 2002, the Corporation updated the soil remediation estimate based on
34 more recent remediation experience and estimated the cost at \$12.959
35 million in 2005 dollars (i.e., prior to inflation), but no change has yet been
36 implemented to the FRSR rates to reflect this full value.
- 37 3) Asset lives, particularly for diesel generation assets are expected to be
38 lower in future studies than assumed in the previous depreciation studies.
39 In the event this is confirmed in the next depreciation study, overall
40 depreciation rates (the sum of amortization of assets and FRSR) will be

⁶ Refiling, p. 19, lns. 14-26.

1 greater than today as the amounts will need to be recovered over a shorter
2 forecast life of assets.⁷

3 A fourth required FRSR related adjustment will account for capital additions that have occurred
4 since 2004/05. From the end of 2004/05 through the 2007/08 test year more than \$20 million in
5 thermal plant is forecast to be added to ratebase.⁸

6 Given the prospect of above adjustments and the fact that an updated depreciation study is not on
7 the record in this proceeding, it would be prudent to approve the FRSR appropriations for the test
8 years as reflected in the Application. The only information available at this time to NTPC and
9 the Board is a preliminary depreciation analysis by NTPC's depreciation experts, which suggests
10 the overall requirement for amortization of assets, including FRSR appropriations, may be higher
11 than presently reflected in NTPC's depreciation rates.⁹ Until a full and updated depreciation
12 study is filed at the Corporation's next GRA, customers are not being prejudiced by any delay in
13 this area, as in the unlikely event the next GRA concludes that there is excess total accumulated
14 amortization, this excess will be available to benefit the customer through lower rates at that
15 time.

16 For the reasons discussed above regarding why approval of the applied for FRSR appropriations
17 are reasonable and having regard to the amount of capital additions installed in 2005/06 and
18 forecast for 2006/07 and 2007/08 which require corresponding FRSR appropriations, the
19 Corporation does not recommend a cap at this time. The current approach is based on the best
20 available evidence from experts in the field.

21 **6. Directive No. 19 – Sales Forecasting Methodology**

22 The fundamental issue for the Board to decide regarding the Corporation's proposed 2006/07
23 and 2007/08 sales forecasts is whether the forecasting methodology applied by NTPC in the
24 GRA is reasonable and should be approved for ratemaking purposes. NTPC submits that the
25 information on the record in the Phase I proceeding, as well as the permutations on the "average
26 use per customer" approach set out in the Refiling and related interrogatories, continue to
27 confirm the reasonableness of both the Corporation's methodology and its forecasts filed in the
28 Application (Exhibits 2 and 13).

29 In considering that issue, it is important to recognize the practical and logistical limitations of
30 substituting a new sales forecasting methodology at this late stage in the process. The
31 Corporation applied the same sales forecasting methodology developed with the help of expert
32 consultants and agreed upon by the interested parties in its 2001/03 GRA. The Corporation was
33 the only party to adduce evidence in support of any sales forecast methodology during the Phase
34 I proceeding. No other party adduced evidence on sales forecasting and methodology. Since
35 then, the Corporation has done its best to address alternative methodologies, but in many cases
36 there simply has not been sufficient time to fully consider, develop and test such alternatives
37 beyond those that can be readily developed and tested based on available information and simple

⁷ Refiling, p. 20, lns. 8-24.

⁸ Refiling, Schedule 5.2.

⁹ Ex. 7, BR.NTPC-14.

1 mathematical approaches.¹⁰ Given those unavoidable limitations, the Board should focus its
 2 consideration on whether the Corporation's proposed 2006/07 and 2007/08 sales forecasts are
 3 reasonable.

4 It is also important to recognize that the Board need not assume that the Corporation's sales
 5 forecasting methodology is beyond continuous improvement. As noted in Refiling IRs
 6 BR.NTPC-(4)(c):

7 [t]he Corporation remains open to testing and evaluating different load forecasting
 8 methods following this GRA, such as the average use per customer method that
 9 may be simpler to apply and understand. If directed by the Board, the
 10 Corporation will undertake to review the average use per customer method for
 11 both Residential and General Service customers as a load forecasting method for
 12 its next Phase I General Rate Application.

13 The Corporation's residential and general service sales forecasting methodology is set out in
 14 Table BR.NTPC-4(d) from the Phase I proceeding.¹¹ The Board, in Directive No. 19, indicated
 15 its desire that "...NTPC should consider historical normalized average use per customer, *among*
 16 *other methods*, in determining its sales forecast for residential and general service customers by
 17 community."¹² The Board did not, as the HC and TGC would recommend, direct the
 18 Corporation to substitute its forecasting methodology entirely for an average use per customer
 19 method. Rather, the Board in prudent fashion directed NTPC to add that methodology to its tool
 20 box among other methods.

21 In the event that the Board is considering substituting the Corporation's forecasting methodology
 22 for another methodology, such as average use per customer, the Board should also reconsider its
 23 decision to reduce NTPC's allowed rate of return on equity for 2006/07 by 40 basis points. The
 24 basis for the Board reducing 2006/07 return on equity was to recognize the risk reduction faced
 25 by the Corporation related to filing the Application about 8 months into the 2006/07 test year.¹³
 26 To that extent, the Corporation was able to include 4 months of actuals in its 2006/07 residential
 27 and general service sales forecasts because the Application was filed after a portion of the
 28 2006/07 test year had elapsed. Should the Board consider substituting the Corporation's forecast
 29 methodology for one that does not include 4 months of actuals in the 2006/07 residential and
 30 general service sales forecasts, such as proposed by the HC, the Corporation would then bear the
 31 forecast risk for the entire 2006/07 test year and the Board's rationale for the 40 basis point
 32 reduction in 2006/07 rate of return would no longer apply.

¹⁰ For example, there has not been sufficient time since Decision 13-2007 was issued for the Corporation to survey other forecast methodologies for residential and general service sales, conduct load research on its general service customers, undertake a regression analysis based on hearing degree days or any other weather related indicator, restate customer counts prior to 2002/03, examine whether average use per customer should be based on 4-year average, 10-year averages, or some larger data set, or develop methods to weather normalize sales at the individual customer or average use per customer level (Refiling, p. 27, lns. 8-20 and p. 28, lns. 1-10; Refiling IRs, BR.NTPC-4(a) and (c), BR.NTPC-5(d)).

¹¹ Ex. 7.

¹² Decision 13-2007 at 134 [emphasis added].

¹³ Decision 13-2007 at 47.

1 For the reasons discussed below, the Corporation's residential and general service sales forecasts
2 are indeed reasonable and should be approved as filed in the Application.

3 **(a) Residential**

4 Regarding residential sales forecasting, the Corporation considered two forms of average use per
5 customer – a simple 4-year average and a weighted 4-year average – the details of which are set
6 out in response to Refiling IRs BR.NTPC-4(b). The Corporation used the 4-year period from
7 2002/03 to 2005/06. The HC recommended using the 4-year period 2001/02 to 2004/05 because
8 2005/06 heating degree days (“HDDs”) are an anomaly relative the 30 year average for Fort
9 Smith (with the same rationale applied to Fort Resolution, Behchoko and Dettah). The HC's
10 suggestion is flawed for the following reasons:

- 11 • the 30-year Normal reported by Environment Canada and relied upon by the HC
12 as their benchmark is the average based on 1971 to 2000, and is therefore not a
13 complete reflection of 30 year average temperature conditions up to 2005/06;
- 14 • for each of Fort Smith, Yellowknife and Inuvik, the 10-year averages are less than
15 the 20-year averages which in turn fall below the 30-year Normal, thus indicating
16 a warming trend through the past 30 years;
- 17 • while the HC's 4-year average from 2001/02 to 2004/05 is relatively close to the
18 30-year Normal (1971 to 2000), it is appreciably higher than either the 20-year
19 average (1986/87 to 2005/06) or the 10-year average (1996/97 to 2005/06);
- 20 • the 4-year average from 2002/03 to 2005/06 considered by the Corporation is a
21 better fit to both the 20-year average and the 10-year average; and
- 22 • while weather, as measured by HDDs, is certainly one factor that could influence
23 average use per customer, there are others, such as weather in the form of
24 precipitation, the state of the local economy and customers ability to pay, and the
25 uptake of different types of energy efficient technologies, all of which impact
26 energy sales and are best reflected in the most recent data available unlike the
27 HC's recommendation.¹⁴

28 If one were to consider a 4-year average use per customer approach, which is not supported by
29 the Corporation, the correct approach and the approach consistent with the Directive No. 19 is to
30 consider a current 4-year (2002/03 to 2005/06) average use per customer metric as compared
31 against its GRA forecasts. As noted in the Corporation's response to Directive No. 19, page 26:

32 [t]he Corporation undertook comparison of the most recent 4-year simple average
33 use per Customer by community for Residential Customers. Corporation wide,
34 the average use per Customer measure produced similar results to the
35 Corporation's existing method (5% variance at the Customer class level). On a
36 Community by Community basis, only three communities in each test year had
37 variance between the two methods of more than plus or minus 8 percent. In
38 consideration of the small numbers of Customers in many of these communities

¹⁴ Refiling IRs, HC-NTPC-5(b&c).

1 and the impact that one household can have on the Residential sales within a
 2 community, the Corporation considers that its method performed well within a
 3 degree of reasonableness compared to the simple average use per Customer
 4 method.

5 The results of that 4-year simple average analysis, as well as a 4-year weighted average analysis,
 6 were presented in Refiling IRs, Tables 1 & 2, BR.NTPC-4(b). Those tables indicate that the
 7 Corporation's GRA residential sales forecasts also compared well against the 4-year weighted
 8 average methodology (2.3% and 2.1% revenue variance for the class in 2006/07 and 2007/08,
 9 respectively). Such a small variance on total forecast residential revenues of \$18.271 million in
 10 2006/07 and \$18,582 million in 2007/08 indicate the reasonableness of the Corporation's
 11 forecasts.

12 In the result, the Corporation's residential sales forecasts, as filed in the Application, have been
 13 further tested by using current 4-year average use per customer methodology as a cross-check.
 14 That additional rigour has further confirmed that Corporation's residential sales forecasts are
 15 reasonable and should be approved by the Board.

16 It is important to note, however, that the Corporation does not recommend use of 4-year average,
 17 as opposed to a longer period, without further consideration. As noted above, there has not been
 18 sufficient time since Decision 13-2007 was issued for the Corporation to examine whether
 19 average use per customer should be based on 4-year average, 10-year averages or some larger
 20 data set. It would be prudent for the Board to direct the Corporation to examine that issue before
 21 specifying a methodology for the next GRA.

22 (b) General Service

23 Regarding general service sales forecasting, the Corporation does not recommend an average use
 24 per customer methodology. In its response to Directive No. 19, page 27, the Corporation noted
 25 the following concerns:

- 26 • Residential Customers tend to be more homogeneous than General Service
 27 Customers. There is a smaller range of consumption levels for Residential
 28 Customers than General Service Customers.
- 29 • There tend to be more Residential Customers in a community than
 30 General Service Customers; therefore changes in the load patterns of one
 31 General Service Customer will have a much greater impact on the class
 32 average.

33 The Corporation then provided a number of examples in Refiling IRs BR.NTPC-5(a) of how
 34 diversity of load patterns or the relative size of general service customers may contribute to
 35 variability in average use per customer. Other factors that impact the variability of average use
 36 per customer are:

- 37 • Non-homogeneous operations as illustrated by the examples provided in
 38 BR.NTPC-5a).
- 39 • Rate of uptake of more energy efficient technologies.

- 1 • Rate of uptake of more electrical equipment.
- 2 • State of the local economy, construction activity, employment, etc.
- 3 • General Service customers have less incentive to conserve if they have the
- 4 ability to pass costs onto their customers.
- 5 • Conformity to current building codes and new technology. For example,
- 6 the new hospital in Inuvik is a larger consumer of energy than the old
- 7 hospital. Although the building is built to a higher energy efficiency
- 8 standard, the air handling systems, lighting, coupled with more
- 9 requirements to meet current codes for such things as electronic diagnostic
- 10 equipment, etc. increase the energy consumed.¹⁵

11 There is no evidence on the record to contradict the Corporation’s conclusion that average use
 12 per customer is not an appropriate methodology for forecasting the Corporation’s general service
 13 sales. In fact, the evidence is that another utility, Manitoba Hydro, does not use average use per
 14 customer to forecast its general service sales.¹⁶ Accordingly, the Board should conclude that the
 15 Corporation’s general service sales forecasts, as filed in the Application, are reasonable and
 16 should be approved.

17 **7. Directive No. 21 – Snare-Yellowknife Water Stabilization Fund**

18 In Directive No. 21 the Board required the Corporation to “...propose in its refiling, a cost
 19 effective approach to excluding the costs and risks associated with generation and transmission
 20 outages from the water stabilization account, having regard to the administrative costs involved,
 21 and to reflect these proposals, in the refiling.”¹⁷ In doing so, the Board expressly recognized that
 22 “...the benefits of an approach designed to isolate different risks must be balanced against the
 23 administrative costs of implementing it.”¹⁸

24 It is important to note at the outset the operating complexities of the Snare-Yellowknife system
 25 and the consequent impact that those complexities can have on how the Snare-Yellowknife
 26 Water Stabilization Fund (the “Water Stab Fund”) operates. Depending upon when, where and
 27 why an outage occurs, as well as current and near-term expected water levels, the dispatch
 28 response may involve diesel generation at Jackfish, hydro generation from other Snare Hydro
 29 units or Bluefish, storing or spilling of water and diesel generation at Behchoko to allow all
 30 hydro generation to serve Yellowknife.¹⁹ As discussed below, the effects of an outage response
 31 in terms of diesel generation may be realized months after the actual outage concludes due to
 32 water levels at the time of the outage, as well as water levels and expected system demand and
 33 energy requirements throughout the next year. The Corporation does not have an hourly
 34 dispatch model that could be used to assess outage events throughout the year and isolate

¹⁵ Refiling IRs, BR.NTPC-5(b).

¹⁶ Refiling, p. 27, footnote 4; Refiling IRs, BR.NTPC-5(d).

¹⁷ Decision 13-2007 at 141-42.

¹⁸ Decision 13-2007 at 141-42.

¹⁹ Refiling IRs, BR.NTPC-6(b) and HC.NTPC-6(a).

1 corresponding diesel generation requirements or provide a probabilistic estimate of the
 2 percentage of time when diesel generation is required to replace hydro generation when a hydro
 3 unit experiences a forces outage.²⁰ Development of such a model would be extremely costly and
 4 have limited benefits given the complexity of the Snare-Yellowknife system and range of
 5 variables which system operators must account for when dispatching generation.

6 Concerns About Changing the Water Stab Fund

7 Notwithstanding that the Corporation has developed an approach to implementing Directive No.
 8 21, the Corporation has serious concerns about the practicality, administrative challenges and
 9 purported benefits of this Directive, as noted below:

- 10 • **Removes clear rules and fairness inherent in current approach.** The present
 11 water stabilization fund fully complies with the 1995/98 GRA Negotiated
 12 Settlement, and has the very beneficial and practical aspects of being completely
 13 transparent and fair to both the Corporation and its customers. In this regard, it is
 14 clear that the existing approach ensures that customers, at the end of the day, will
 15 pay exactly what NTPC incurs for diesel fuel, no more and no less. Given the
 16 extreme difficulties in forecasting, deciphering and tracking the relative uses of
 17 diesel fuel on a complicated hydro-based system, the “deferral account” type
 18 benefit of the current approach is an appropriate regulatory mechanism. As an
 19 example, the Newfoundland Island Interconnected system (a similar mixed hydro-
 20 thermal system to Snare-Yellowknife system) operates a Rate Stabilization Plan
 21 that includes a hydro component very similar to the current Water Stab Fund, in
 22 that it operates off *actual* hydro and thermal generation, without adjustment for
 23 parcelling off outages versus overhauls versus uninsured losses, as would be the
 24 case if the Corporation’s response to Directive No. 21 is incorporated into the
 25 Board’s final decision.²¹
- 26 • **Requires potentially contentious approaches to implement as part of a GRA.**
 27 NTPC has had little time to determine a single acceptable approach to forecasting
 28 the amount of diesel fuel that will typically be required for the very uncertain and
 29 hard to predict situations of outages on the Snare-Yellowknife system. Although
 30 the forced outage rate approach (as discussed below) offers clear benefits in terms
 31 of utilizing PUB-approved variables, the specific means to apply this to a test year
 32 may yet be the subject of much debate.
- 33 • **Is likely to be extremely difficult to implement over time, to track and report
 34 to the Board’s and intervenors’ satisfaction, and to test at future regulatory
 35 proceedings.** Outside of a GRA proceeding, the new approach will require
 36 NTPC to fully account for all diesel on the Snare-Yellowknife system by
 37 subdividing this total fuel volume into the various categories that drive its use.
 38 This is likely to be extremely complicated and subject to much debate and

²⁰ Refiling IRs, BR.NTPC-6(b).

²¹ Newfoundland and Labrador Board of Commissioners of Public Utilities Decision and Order of the Board, Order No. P.U.7 (2002-2003), dated June 7, 2002. A copy of this Decision and Order can be obtained at <http://n225h099.pub.nf.ca/hyd01gra/order/pu7-03.pdf>.

1 retrospective review at future GRAs. For example, depending on the type of
 2 outage and timing, there are situations where the resulting diesel may not be
 3 readily identified at the concurrent point in time, but instead occur at a much later
 4 date.²² The Corporation noted this difficulty in Refiling IRs BR.NTPC-6:

5 In order to implement a discretionary aspect to the fund, that is to
 6 determine that some diesel generation will flow through to the fund
 7 while other diesel generation will be excluded, requires a degree of
 8 judgment and subjectivity. It simply is not possible to say with
 9 absolute certainty in all occasions whether a kW.h of diesel
 10 generation was incurred as the result of a forced outage at a hydro
 11 unit, or as a result of normal generation dispatch or is exercising
 12 the unit. It is also extraordinarily difficult to forecast diesel
 13 generation requirements on the basis of whether it will be required
 14 as the result of a forced outage or a normal generation dispatch
 15 requirement in any meaningful way.

16 And in its response to Refiling IRs BR.NTPC-8.

17 There are a variety of limitations to this method. The most serious
 18 limitation is that it is difficult at best and at times not a meaningful
 19 exercise to attempt to attribute the use of diesel generation to a
 20 particular cause at any given point in time. This would make it a
 21 difficult and often subjective exercise in practice to determine
 22 whether a kW.h of diesel generation should be an operations and
 23 maintenance expense, charged to the water stabilization fund, part
 24 of a capital project or charged to the reserve for injuries and
 25 damages. In any event, the treatment is likely to be at least
 26 partially subjective, as well as difficult to explain and interpret.

27 A situation on the Snare-Yellowknife system that is likely to arise is instructive in
 28 this regard. Presently, the Bluefish generating station is undergoing a capital
 29 works program. As a result, Bluefish generation is not available for supplying the
 30 Snare-Yellowknife system. To compensate for this loss of hydro, the “normal”
 31 autumn generation mix is being supplemented by diesel generation, and by
 32 increased use of stored water at Snare hydro. Consequently, it is reasonable to
 33 expect that once the Bluefish capital work is completed, Snare hydro will operate
 34 with less stored water than would be typical for this time of year and less water
 35 would otherwise be available had the Bluefish capital work not occurred. In that

²² One example in this regard occurred in Yukon in the late 1990s, where a fire at the Whitehorse Rapids plant in October 1997 resulted in required water management adaptation, which ultimately led to diesel generation in spring 1999 being identified as fire-related. After a lengthy debate with the insurers, including review of extensive system modelling evidence, the insurers agreed that this diesel generation, more than 18 months after the event in question, was related to the fire and compensated Yukon Energy for the generation. Similar situations could readily arise in NWT, given the relative ability to use either diesel generation or stored water at the time of an outage, and in the event stored water is used it would be unavailable for future generation as it would have otherwise been but for the outage in question. See Yukon Utilities Board Order No. 2002-3, Appendix A, dated November 6, 2002. A copy of this order can be obtained at http://www.yukonutilitiesboard.yk.ca/pdf/100_boardorder2002_3.pdf.

1 case, in order to supply the upcoming winter load requirements, Snare hydro
 2 generation would be lower than what would otherwise be achievable, with more
 3 diesel generation being dispatched. This means that, at a minimum, there would
 4 be diesel generation in November and possibly December, 2007 related to the
 5 Bluefish capital project, even though the project will be completed by that time.
 6 In the event this upcoming winter is characterized by low water, or is subject to
 7 some measure of forced outages, it will become nearly impossible to decipher
 8 which unit of diesel generation was related exactly to which event. However,
 9 such deciphering will now be required (and is likely to be fully second guessed at
 10 future GRAs) as the decision as to whether the diesel is due to outages, versus
 11 capital, versus low water, versus overhauls, etc. is a driving factor in whether it
 12 will be included in future rates or be expensed in the present year fiscal.

- 13 • **The benefits of the approach are of uncertain value, compared to the costs**
 14 **and risks.** Considering the obvious benefits and transparency of the existing
 15 system, and the obvious extreme challenges of implementing and tracking the
 16 Board's Directive, it is not clear how this new approach is expected to benefit
 17 anyone (NTPC or its customers) in terms of regulatory approaches. As noted
 18 above, Newfoundland uses an approach consistent with the existing Water Stab
 19 Fund and has had little to no complicated regulatory debate over the amounts
 20 charged to the hydro component of its fund for over two decades. Similarly, the
 21 Corporation's Water Stab Fund account has operated largely as planned at the
 22 outset, without controversy or difficulty, since it was established.

23 In addition to the above noted concerns, the recognition of hydro plant and transmission outages
 24 as part of the Corporation's risk was not incorporated whatsoever into the risk assessments
 25 conducted by either Ms. McShane or Drs. Kryzanowski and Roberts. Directive No. 21 imposes
 26 new risks for which the Corporation is not compensated (and corresponding new risks on its
 27 customers), and for which the Board (and indeed NTPC and interested parties at this point in
 28 time) have no evidence as to frequency or magnitude of the risk being borne. Further,
 29 maintaining the Water Stab Fund as it currently operates would avoid the need to build an
 30 allowance for outages into rates and the corresponding \$584,000 for fuel expense in 2006/07
 31 revenue requirement in and \$653,000 in 2007/08.²³

32 The Corporation's Refiling Approach

33 Having recognized the limits and challenges of the unavoidable introduction of discretionary
 34 variables, the Corporation has advanced a proposal that identifies three types of hydro generation
 35 and transmission outages – forced outages, outages due to capital projects and planned
 36 maintenance outages – and ensures that diesel generation costs clearly related to those types of
 37 outages are excluded from the Water Stab Fund.

38 As noted in the Corporation's response to Directive No. 21, page 31, hydro and transmission
 39 forced outages are based on the forced outage rates previously approved by the Board in
 40 Decision 14-2004 for the Snare Hydro system as a whole,²⁴ the L-199 transmission line and the

²³ Refiling IRs, Table 2, HC.NTPC-6.

²⁴ Refiling IRs, BR.NTPC-6(a).

1 Bluefish transmission line. Using previously approved forced outage rates respects the Board's
2 caution about administrative costs.

3 Implementing the approach of not charging diesel generation required for forced outages to the
4 Water Stab Fund, but rather including them in Revenue Requirement for the test years, requires
5 2.97 GW.h and 3.02 GW.h of additional diesel generation (and forecast fuel expenses) in
6 2006/07 and 2007/08, respectively, based on the forecast hydro generation. That amount is
7 offset by 0.841 GW.h in 2006/07 to account for the fact that NTPC's original filing included 4
8 months of actuals in its Snare-Yellowknife diesel generation forecast, which requires the impact
9 on fuel expenses related to outages and capital projects to be removed.²⁵ The result is a total
10 Snare-Yellowknife diesel generation requirement of 4.24 GW.h in 2006/07 and 4.40 GW.h in
11 2007/08.

12 Of those amounts, 1.27 GW.h in 2006/07 and 1.38 GW.h in 2007/08 relate to peaking and
13 exercising requirements. Since the Board did not direct the Corporation to propose an alternative
14 treatment for diesel generation related to peaking and exercising, the Corporation has maintained
15 the previous treatment of this diesel generation, netting it off of the test year revenue requirement
16 as items that would continue to flow through the water stabilization fund. The remaining diesel
17 generation (2.97 GW.h in 2006/07 and 3.02 GW.h in 2007/08) relates to forced outages and will
18 need to be built into the test years' revenue requirements to be included in final rates.

19 Using forced outage rates to make this estimate is a readily measurable and practical approach.
20 It is important to note, however, that forced outage rates are long-term averages of system
21 performance and in many years the actual outages can be either well below this level or well
22 above it. As an example, Refiling Table 1, BR.NTPC-6 indicates that for the last three years of
23 actuals, diesel generation required as a result of forced outages would have been somewhat
24 below this long term average level, as well as having an extremely wide range over just those
25 three years. In the event the Board maintains this directive in its final Order, NTPC will be at
26 risk for this variability in forced outages, which will require consideration in future assessments
27 of the appropriate risk-based Return on Equity for the utility.

28 Commencing with 2006/07, the diesel generation expenses during outages related to hydro and
29 transmission capital projects will be capitalized as part of project costs on an individual project
30 by project basis, as opposed to being applied to the Water Stab Fund. The Corporation does not
31 propose to reallocate diesel generation related to capital projects incurred prior to the test years.²⁶
32 No change to diesel generation requirements or fuel expenses is required.

33 Outages related to both hydro and transmission planned maintenance, as is normal practice, will
34 be conducted during periods of low generation requirements to the extent possible, and the
35 related diesel generation expenses will be charged to income and not charged to the Water Stab
36 Fund. Notwithstanding that these amounts will be charged to income in future years under the
37 Refiling, there has been no amounts included in the Refiling Revenue Requirement for those
38 costs, as they are difficult to forecast and likely sufficiently small that they will replace the need
39 to exercise the engines in that month.

²⁵ Refiling, p. 31 & 33; HC.NTPC-6(e).

²⁶ Refiling IRs, HC.NTPC-6(c).

