THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 1-2013 **JANUARY 21, 2013**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories for the Test Years 2012/13 and 2013/14.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	Joe Acorn	Chairman
	Sandra Jaque	Vice-Chairman
	William Koe	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	Evan W. Dixon	Board Counsel

APPEARANCES

Karen Salmon	Counsel for the Northwest Territories Power Corporation
Thomas D. Marriott	Counsel for the City of Yellowknife & Town of Hay River
G. Rangi Jeerakathil.	Counsel for the Thermal Generation Communities

WITNESSES

Northwest Territories Power Corporation

Judith Goucher	Chief Financial Officer
Terence Courtoreille	Manager, Budgeting & Regulatory Affairs
Daniel Roberts	Director of Engineering & Asset Management
Patrick Bowman	Consultant

WITNESSES cont…

City of Yellowknife & Town of Hay River

Russ Bell	Consultant

TABLE OF CONTENTS

1. BACKGROUND & APPLICATION

By letter dated March 23, 2012, the Northwest Territories Power Corporation (“**NTPC” or the “Corporation**”) submitted to the Northwest Territories Public Utilities Board (“**the Board**”) it’s General Rate Application (“**GRA, Application**”). The Application outlines forecast costs for providing electricity service for the 2012/13 and 2013/14 fiscal years (the “**Test Years**”) [Ex 2].

In conjunction with its GRA and pursuant to Section 44 of the *Public Utilities Act* (“***the Act***”), NTPC also filed an Interim Rate Application (“**IRA**”) dated March 23, 2012 wherein it requested approval of interim rates to increase all energy charges for all customer classes, in all communities, except Norman Wells, by 7% and for interim rates to increase all energy charges for all customer classes in Norman Wells by 15%. NTPC also requested that all interim rates be effective April 1, 2012. NTPC stated that to be consistent with the 2012/14 GRA, NTPC was not seeking to adjust customer charges or demand charges.

In previous interim rate applications, NTPC has proposed interim rate riders to collect approximately 80% of the Corporation’s shortfall that would result from fully implementing the proposed revenue requirement in the GRA, subject to a maximum overall rate increase of 15%. In the current GRA, NTPC proposed to transition to rates that fully recover the Corporation’s revenue requirement over a four-year period.

For the 2012/13 Test Year, NTPC requested approval of final rates that are 7% higher than current rates for all communities and rate classes except Norman Wells, where 15% energy rate increases are proposed to assist with the transition of Norman Wells into the Thermal zone as per Provision (9)(a) of the February 10, 2011 Rate Policy Guidelines.

Despite the additional revenue from interim rates, NTPC still expects to incur a substantial shortfall in the 2012/13 Test Year. As a result, NTPC indicates, the Corporation and its shareholder, the Government of the Northwest Territories (“**GNWT**”), have implemented financial funding measures which will mitigate the rate impact for customers during this transition. With these measures NTPC indicates, it can continue to provide safe and reliable service, while maintaining its financial viability for 2012/13.

By letter, dated March 28, 2012, the Corporation stated that it wished to amend its IRA to reduce the requested increase for all customer classes in Norman Wells from 15% to 7%, effective April 1, 2012. This amendment will bring Norman Wells’ proposed increases in line with the increases in energy charges sought for all customers in all other communities.

The Board issued Decision 11-2012, dated May 1, 2012, approving rates on an interim refundable basis, effective May 1, 2012 for the 2012/13 year. In its Order, the Board directed that all revenues collected by the interim rates are to be tracked by zone and rate class to allow reconciliation and true-up in accordance with the final GRA Decision.

In its GRA, the Corporation requested an order or orders of the Board:

1. **Approving the Test Year Revenue Requirements** at $102.506 million and $107.544 million in 2012/13 and 2013/14 respectively, including approval as required of the following costs and revenues:

   a. **Operating and Maintenance Expenses** of $37.280 million and $38.634 million for non-fuel expenses in 2012/13 and 2013/14 respectively.

b. **Fuel Expenses** of $27.538 million and $27.879 million for fuel and purchased power expenses in 2012/13 and 2013/14 respectively, including approvals to establish fuel prices at forecast levels for the two test years at the most recent prices charged by the GNWT Petroleum Products Division ("PPD") as of February 2012, with actual variances from forecast being charged to or credited to NTPC's territory-wide Stabilization Fund.

c. **Amortization Expenses** (net of customer contributions) of $13.298 million and $13.363 million in 2012/13 and 2013/14 respectively for fixed assets, plus $2.584 million in 2013/14 for the fixed asset true-up, plus $5.280 million and $5.747 million in 2012/13 and 2013/14 respectively for other amortization, including approvals:

   i. To adopt new asset amortization rates as determined in NTPC's 2011 Depreciation Study performed by Gannett Fleming for all asset classes.

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

   iii. To implement a pause in accruals for future removal and site restoration ("net salvage") until such time as a future depreciation study indicates the balance in the provision equals the expected future spending requirements.

   iv. To decrease the annual appropriation for regulatory hearing costs from the $0.600 million per year level set at the 2006/08 GRA, to $0.243 million per year, reflecting the full recovery of the costs of all past GRAs, and the assumed costs for preparation and regulatory review of the 2012/13 and 2013/14 GRA on a simplified basis (total assumed incremental cost to NTPC of $1.3 million).

v. To increase the annual amortization of the normalized overhaul deferral account from an annual level of $1.693 million per year approved in the 2006/08 GRA to $3.046 million per year to reflect increases in the balance and in the forecast ongoing costs of overhauls primarily in the thermal zone.

vi. To increase the annual amortization of the water licencing deferral account from an annual level of $0.137 million per year approved in the 2006/08 GRA to $0.751 million per year in 2012/13 and $1.175 million per year in 2013/14 to reflect material increases in the balance in the account and in the forecast level of effort and spending required to maintain and renew NTPC's water licences including regulatory reviews, compensation, environmental and dam safety studies, Aquatic Effects Monitoring Program ("AEMP") costs and all related activities (except capital works).

vii. Continuation of the Reserve for Injuries and Damages, at the same $0.670 million per year appropriation approved in the 2006/08 GRA.

viii. A new annual amortization of $0.348 million per year to begin to discharge the balance in the regulatory Employee Future Benefits deferral, established as part of the 2001/03 GRA Negotiated Settlement. This account has previously had no annual accrual pending a full draw down of the balance that was established in the 2001/03 GRA, which has now occurred.

ix. A new brushing deferral approach to amortize all brushing costs in a given year over the following 10 years, including approval to amortize $0.088 million in 2012/13 and $0.132 million in 2013/1 4.

x. Amortization of all remaining deferred charges over 5 years except in cases where the anticipated benefits exceed this level (specifically, 10 year amortization for IFRS conversion project costs, and for the Enterprise Resource Planning exercise).

d. **Return on Rate Base** of $19.111 million and $19.337 million in 2012/13 and 2013/14 respectively, reflecting an underlying forecast capital structure financing rate base of approximately 40% equity and 60% longterm debt and capital lease, including the following proposed costs of capital:

   i. Mid-Year Cost of Long-Term Debt of 6.54% and 5.77% in 2012/13 and 2013/14 respectively.

   ii. Average Cost of Capital Lease of 9.62% in each test year. Return on Equity in the Thermal Zone of 0% consistent with the Guidelines.

   iii. A requested Return on Equity for all assets outside the Thermal Zone of 8.5% determined on a simplified basis given the requested rate is below market standards recently set for utilities in Canada, such as the 8.75% low risk benchmark approved by the Alberta Utilities Commission for lower-risk large southern electric utilities (2011 and 2012 and interim 2013), and the 9.3% approved for NUL(YK) and NUL(NWT) (2011, 2012, and 2013).

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

2. **Approving the Forecast Test Year Rate Base** at $273.522 million and $296.125 million in 2012/13 and 2013/14 mid-years respectively (Chapter 4), reflecting the net book value of assets in service, customer contributions, other deferred charges, and an allowance for working capital, including additions made to rate base pursuant to the following projects subject to PUB Project Permits:

a. **Bluefish Dam Replacement Project** in 2012/13, at a forecast cost of $37.4 million consistent with Board Decision 15-2011.
b. **Inuvik Diesel Conversion Project** at an estimated $8 million, not yet in receipt of a PUB Project Permit, to address the extenuating circumstances arising from the shortfall in gas supply.

3. **Approving final GRA rates to be charged to customers** covering the rate transition period (including the 2 Test Years plus 2014/15 and 2015/16) as needed to achieve the full calculated level of rates.

a. **Residential Non-Government:** Increases to all energy rates, other than Norman Wells, totalling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 201 5/16 to achieve Full Rates. For Norman Wells increases to energy rates of 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. No changes are proposed to fixed monthly charges.
b. **Residential Government:** Increases to customer energy rates equal to the same percentage as the increase in non-government customer energy rates in the same community. No changes are proposed to fixed monthly charges.
c. **General Service Non-Government:** Increases to all energy rates, other than Norman Wells, totalling 7% in each of 2012/13, 201 3/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells increases to energy rates totalling 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 20 15/16. No changes are proposed to demand charges.
d. **General Service Government:** Increases to customer energy rates equal to the same percentage as the increase in non-government General

Service customer energy rates in the same community. No changes are proposed to demand charges.

e. **Wholesale:** Increases to customer energy rates of 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. No changes to demand charges.

f. **Industrial:** Increases to customer energy rates of 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. No changes to demand charges.

g. **Lighting:** Increases to lighting rates equal to the same percentage applied to Government General Service in the same community.

4. **Approving revised Terms and Conditions of Service** primarily focused on standardizing the Corporation's terms with normal utility provisions (including provisions with respect to liability and indemnity), to address potential safety issues with respect to reconnections, to improve the clarity and consistency of the terms, as well as general housekeeping updates.

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated April 12, 2012, directed NTPC to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories ("**NWT**"). The notices published in April 2012 included details and schedules of the GRA, and invited interested persons to file a request with the Board for intervener status. [Ex 1]

The City of Yellowknife and Town of Hay River (collectively referred to as "**YK/HR**") registered to participate as interveners in the Board's process as did the Thermal Generation Communities, comprised of the Town of Inuvik, Hamlet of Fort Providence and Village of Fort Simpson (hereinafter the "**TGC**").

The Board's hearing process provided interveners with the opportunity to request further information of NTPC through an information request process as well as the ability to file evidence.

In accordance with the schedule set by the Board, NTPC provided written responses to the information requests [Ex 3] from the Board and interested parties. Written evidence was filed on behalf of YK/HR, by letter dated June 29, 2012 [Ex 6]. The TGC did not provide written evidence but were active in the information request process and the public hearing. Information requests were issued by the Board and NTPC to YK/HR in response to their written evidence [Ex 7]. All written information requests by the Board and interveners together with the responses were made available to all parties before the hearing and form part of the public record of this hearing.

By letter dated September 19, 2012, NTPC provided an updated filing package with respect to NTPC's GRA pursuant to its letter of June 8, 2012 and Board Decisions 16-2012 and 22-2012. The package included updated GRA schedules and updated information on Norman Wells transitioning to the Thermal Zone rates [Ex 13].

The update requested the following approvals:

"1. ***Approving the Test Year Revenue Requirements*** *at $102.225 million and $107.304 million in 2012/13 and 2013/14 respectively (Chapter 3), including approval as required of the following costs and revenues:*

  a. ***Operating and Maintenance Expenses*** *of $37.064 million and $38.597 million for non-fuel expenses in 2012/13 and 2013/14 respectively.*

  b. ***Fuel Expenses*** *of $27.817 million and $28.172 million for fuel and purchased power expenses in 2012/13 and 2013/14 respectively, including approvals to establish fuel prices at forecast levels for the two test years at the most recent prices charged by the GNWT Petroleum Products Division ("PPD") as of August 2012 February 2012, with actual variances from forecast being charged to or credited to NTPC's territory-wide Stabilization Fund.*

c. ***Amortization Expenses*** *(net of customer contributions) of $13.240 million and $13.503 million in 2012/13 and 2013/14 respectively for fixed assets, plus $2.584 million in 2013/14 for the fixed asset true-up, plus $5.170 million and $5.287 million in 2012/13 and 2013/14 respectively for other amortization, including approvals:*

i. *To adopt new asset amortization rates as determined in NTPC's 2011 Depreciation Study performed by Gannett Fleming (Appendix A) for all asset classes.*

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

iii. *To implement a pause in accruals for future removal and site restoration ("net salvage") until such time as a future depreciation study indicates the balance in the provision equals the expected future spending requirements.*

iv. *To decrease the annual appropriation for regulatory hearing costs from the $0.600 million per year level set at the 2006/08 GRA, to $0.243 million per year, reflecting the full recovery of the costs of all past GRAs, and the assumed costs for preparation and regulatory review of the 2012/13 and 2013/14 GRA on a simplified basis (total assumed incremental cost to NTPC of $1.3 million).*

v. *To increase the annual amortization of the normalized overhaul deferral account from an annual level of $1.693 million per year approved in the 2006/08 GRA to $2.936 million per year to reflect increases in the balance and in the forecast ongoing costs of overhauls primarily in the thermal zone.*

vi. *To increase the annual amortization of the water licencing deferral account from an annual level of $0.137 million per year approved in the 2006/08 GRA to $0.751 million per year in 2012/13 and $0.825 million in 2013/14 to reflect material increases in the balance in the account and in the forecast level of effort and spending required to maintain and renew NTPC's water licences including regulatory reviews, compensation, environmental and dam safety studies, Aquatic Effects Monitoring Program ("AEMP") costs and all related activities (except capital works).*

vii. *Continuation of the Reserve for Injuries and Damages, at the same $0.670 million per year appropriation approved in the 2006/08 GRA.*

viii. *A new annual amortization of $0.348 million per year to begin to discharge the balance in the regulatory Employee Future Benefits deferral, established as part of the 2001/03 GRA Negotiated Settlement. This account has previously had no annual accrual pending a full draw down of the balance that was established in the 2001/03 GRA, which has now occurred.*

ix. *A new brushing deferral approach to amortize all brushing costs in a given year over the following 10 years, including approval to amortize $0.088 million in 2012/13 and $0.132 million in 2013/14.*

x. *Amortization of all remaining deferred charges over 5 years except in cases where the anticipated benefits exceed this level (specifically, 10 year amortization for IFRS conversion project costs, and for the Enterprise Resource Planning exercise).*

d. ***Return on Rate Base*** *of $18.934 million and $19.161 million in 2012/13 and 2013/14 respectively, reflecting an underlying forecast capital structure financing* *rate base of approximately 40% equity and 60% long-term debt and capital lease, including the following proposed costs of capital:*

- *i.* *Mid-Year Cost of Long-Term Debt of 6.47% 6.54% and 5.68% 5.77% in 2012/13 and 2013/14 respectively.*
- *ii.* *Average Cost of Capital Lease of 9.62% in each test year.*
- *iii.* *Return on Equity in the Thermal Zone of 0% consistent with the Guidelines.*
- *iv.* *A requested Return on Equity for all assets outside the Thermal Zone of 8.5% determined on a simplified basis given the requested rate is below market standards recently set for utilities in Canada, such as the 8.75% low risk benchmark approved by the Alberta Utilities Commission for lower-risk large southern electric utilities (2011 and 2012 and interim 2013), and the 9.3% approved for NUL(YK) and NUL(NWT) (2011, 2012, and 2013).*
- *v.* *An interest coverage ratio in the thermal zone of 1.5.*

2. ***Approving the Forecast Test Year Rate Base*** *at $272.778 million and $296.592 million in 2012/13 and 2013/14 mid-years respectively (Chapter 4), reflecting the net book value of assets in service, customer contributions, other deferred charges, and an allowance for working capital, including additions made to rate base pursuant to the following projects subject to PUB Project Permits:*

- ***a)*** ***Bluefish Dam Replacement Project*** *in 2012/13, at a forecast cost of $37.4 million consistent with Board Decision 15-2011.*
- ***b)*** ***Inuvik Diesel Conversion Project*** *at an estimated $10.3 million, including $7.7 million approved via PUB Project Permit, to address the extenuating circumstances arising from the shortfall in gas supply.*

3. ***Approving final GRA rates to be charged to customers*** *covering the rate transition period (including the 2 Test Years plus 2014/15 and 2015/16) as needed to achieve the full calculated level of rates (Chapter 4).*

- ***a)*** ***Residential Non-Government:*** *Increases to all energy rates, other than Norman Wells, totaling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells increases to energy rates of 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. No changes are proposed to fixed monthly charges.*
- ***b)*** ***Residential Government:*** *Increases to customer energy rates equal to the same percentage as the increase in non-government customer energy rates in the same community. No changes are proposed to fixed monthly charges.*
- ***c)*** ***General Service Non-Government:*** *Increases to all energy rates, other than Norman Wells, totaling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells increases to energy rates totaling 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. No changes are proposed to demand charges.*
- ***d)*** ***General Service Government:*** *Increases to customer energy rates equal to the same percentage as the increase in non-government General Service customer energy rates in the same community. No changes are proposed to demand charges.*
- ***e)*** ***Wholesale:*** *Increases to customer energy rates of 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. No changes to demand charges.*

f) ***Industrial:*** *Increases to customer energy rates of 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. No changes to demand charges.*

g) ***Lighting:*** *Increases to lighting rates equal to the same percentage applied to Government General Service in the same community.*

4. ***Approving revised Terms and Conditions of Service*** *(Chapter 7) primarily focused on standardizing the Corporation's terms with normal utility provisions (including provisions with respect to liability and indemnity), to address potential safety issues with respect to reconnections, to improve the clarity and consistency of the terms, as well as general housekeeping updates."*

2. PUBLIC HEARING

The hearing was held in the City of Yellowknife on September 26 and 27, 2012. During the course of the hearing, members of the public who had not requested intervener status were invited to participate. During the hearing, NTPC undertook to provide responses to a number of undertakings provided at the hearing.

Following the hearing, undertaking responses and Argument/Reply were filed on the following dates:

Responses to Undertakings	October 9, 2012
Information Requests on Undertakings	October 11, 2012
Responses to Information Requests	October 15, 2012
Written Argument	October 24, 2012
Written Reply Argument	November 7, 2012

3. RATE BASE

NTPC's mid-year rate base for the Test Years 2012/13 and 2013/14 includes:

- Gross plant in service, including capital additions and disposals
- Accumulated amortization
- Customer contributions
- Working capital
- Deferral accounts

The calculation of the mid-year rate base is set out in Schedule 5.1

3.1 Gross Plant In Service

NTPC's calculation of gross plant in service is shown in Schedule 5.1.

TGC requested that the 2012/13 Test Year opening balances for gross plant in service be updated to reflect the 2011/12 actual closing balances for plant. The Board will deal with this matter in Section 13.1 of this Decision.

3.2 Accumulated Amortization

NTPC's calculation of accumulated amortization is set out in Schedule 5.1.

TGC requested that the 2012/13 Test Year opening balances for Accumulated Amortization be updated to reflect the 2011/12 actual closing balances. The Board will deal with this matter in Section 13.1 of this Decision.

3.3 Capital Additions

NTPC summarized capital spending for 2010/11 and forecasts for 2011/12, 2012/13 and 2013/14 in Appendix B of the Application. In Appendix B, the Corporation provided additional detail for those projects over $150,000 including those projects previously approved by the Board through Major Project Permit Applications.

The issues respecting capital additions that were raised during the proceedings are discussed below.

3.3.1 Capital Budgeting and Business Cases

NTPC acknowledged that its record in the years leading up to the 2009/10 NTPC Review conducted by a Panel of Experts, had not been acceptable with respect to project scoping, cost estimating and budgeting. In this regard, NTPC quotes the Panel's comments as follows:

> *"Cost estimates and project scope do not appear to be as well planned as one could reasonably expect. For example, with the Snare Rapids Upgrade, the original budget was targeted at $4.92 million, but eight years later expenditures had risen to $9.5 million. The first 5 years of work consumed most of the original budget. Better scoping at the outset should have allowed for, among other reasonable projections, a better estimate of the condition of the facility and its parts."* [Ex 8; P2]

During hearing examination NTPC's witness, Mr. Roberts, indicated several changes designed to address project scoping and accuracy of cost estimating have been put in place since the Panel Review. First, a reorganized structure has been put in place:

> *"So under the reorganization structure the first thing that will be addressed is the estimates and the accuracy of the estimates. To achieve that, we have asset managers who are responsible for the planning. And we have a dedicated asset manager now for the hydro and a dedicated asset manager position for the Thermal plants and also for the T&D. And where it refers to the team approach, what that means is they'll be assessing the projects and looking at the condition of the assets, but they'll be working in conjunction with our design team so that we can have better estimates for the -- upfront. So there was clearly some problems with using estimates that were weren't up-to-date. So that's the first thing that will be addressed."* [T264; L9-25]

Second, there will be more emphasis on scoping of projects:

> *"…So where it says scope creep, it's not really, it's the fact that the project should have included all this at the start if it's evaluated correctly. So the projects will be -recent estimates which I saw -- like I say, not just this project, I saw quite a few projects that we were using estimates significantly out-of-date. And also there will be more emphasis put on the scoping of these projects."* [T265; L12-20]

Third, the issue of completeness of cost estimates is to be addressed:

> *"And the third issue that I saw is around the completeness, I'll call it, of the estimates themselves. Quite often the estimates that were put forward in our capital plan would have included estimates for contractors and materials which --excepting they want were out of date, they were --but there were also -- I would say weren't complete, they didn't fully include costs like construction supervision or travel to site wasn't accurate -- wasn't accurate enough, design, engineering costs were underestimated. So it's pretty clear that we have to address these issues to up come up with more realistic budgets."* [T265, L21 – T266, L8]

Mr. Roberts confirmed that there will be ongoing monitoring of projects and if a larger project in the $50,000 to $75,000 range looks like it is going over budget it is flagged at an early stage. [T269, L5-9] Where project costs are expected to be $100,000 over the budget they are required to be brought to the attention of the Board of Directors. [T269, L17-22]

In terms of accountability tools, NTPC was questioned as to whether post-completion reports are prepared when projects are completed, looking at variances and lessons learned for future budgeting purposes. Mr. Roberts indicated: "I haven't seen them but we will be doing them." [T268, L11]

Ms. Goucher referred to other accountability tools used by NTPC:

> *"…We do have also some specific accountability tools in terms of adherence to budget targets. In terms of the management team, I believe it was Mr. Courtoreille who identified that one of the criteria of the at-risk performance pay is that our capital program be delivered overall within certain budget tolerances, otherwise the entire management team could have -- could lose any at-risk compensation for that fiscal year.*
>
> *In terms of the individual project managers and other employees within the engineering group or other groups who are responsible for project management, we also complete, as an organization, annual performance reviews. Those reviews speak to specific skills gaps and performance deficiencies, and we identify training programs out of those. So that would be another tool that's available to the management team in terms of making sure that we reach the success level that we're seeking in terms of project management."* [T271, L18 – T272, L13]

YK/HR expressed concern that the Corporation did not provide business cases in support of certain major capital projects. YK/HR noted that businesses cases for the Snare/Jackfish Transient Stability Upgrade project and the Distribution System Upgrade project, the land use database, and the computerized maintenance system had not been provided by NTPC. YK/HR recommended, on the basis of NTPC having not identified any tangible benefits to the land use data base project with a cost of $430,000, and the computerized maintenance system at a cost of $413,000, that the Board deny the inclusion of these projects in approved rate base. [YK/HR Argument, P7, Para 26]

YK/HR also recommended that NTPC provide business cases in support of capital programs, to include the following:

- A full and complete discussion of the business need that is being addressed.
- A list of all assumptions made, including the source and basis for the assumptions.
- An analysis of all reasonable options that could be pursued, including the do nothing option.

- Cost projections over the life of the project, for each option to allow the assessment of the total lifecycle cost of the project. This should include all costs of the project.
- Appendices that provide the calculation of costs included in the business case.
- Projected tangible benefits, along with the basis for the projected benefits.
- Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome.
- Present value of revenue requirement.
- Traditional cash flow analysis.
- A discussion of all intangible benefits.
- A complete discussion of risks and mitigation strategies related to the project and the recommended option. [YK/HR Argument Para 11]

YK/HR noted that NTPC has additional information, and conducts a more detailed analysis for internal management purposes. As such, and in order to enhance the efficiency and transparency of the regulatory process, YK/HR suggested that NTPC should be directed to provide complete business cases to support capital expenditures for a GRA as part of the minimum filing requirements [YK/HR Argument, P3, Para 12]. YK/HR recommended a materiality threshold of $400,000 for filing of business cases. [Ex 6, P13, Para A11]

YK/HR submitted, expenditures that are a part of a larger program should be analysed and justified together. In this regard, YK/HR noted that NTPC is forecasting to spend over $500,000 per year on IT projects for each of 2012/13 and 2013/14, yet has not provided a business case or its internal IT policy, nor evidence that its policies and practices result in the least cost option for customers. [YK/HR Argument, P1, Para 5]

With respect to the proposed Remote Terminal Unit ("**RTU**") replacement, YK/HR submitted:

> *"..NTPC is forecasting to spend $876,000 in 2012/13 and $1,491,000 in 2013/14, yet has provided limited explanations for its forecast. NTPC has not provided a business case in support of the level of spending forecast for 2013/14. While NTPC has explained what the expenditures are for, NTPC has not explained why the increased spending in 2014 is*

> *required. In fact, YK/HR notes that the original budget for the entire project was $2.5 million, and the revised budget is $4.2 million. Further, NTPC indicates it has spent $3.4 million of the $4.2 million. Given that NTPC has spent $3.4 million of the $4.2 million budget, YK/HR does not understand why an additional $2,367,000 is to be spent over the 2012/13 2013/14 period. According to NTPC, there is only $0.8" million left to be spent. Given the history of spending and the fact that NTPC's own budget indicates that there is only $0.8 million left in the project, YK/HR submits that the forecast spending on RTU replacement be reduced to $0.8 million to represent the level of spending left to in the project budget."* [YK/HR Argument, P7, Para 27]

NTPC responded to the positions taken by YK/HR in its Rebuttal and in Reply Argument.

With respect to YK/HR's recommendation that the computerized maintenance system costs and the land use data base costs be disallowed, NTPC submitted that business cases are only relevant where an optional project is being pursued for reasons of a positive financial return. NTPC submitted that neither project cited by YK/HR meets these criteria. NTPC further submitted that the referenced projects are essential core utility functions which cannot be properly portrayed by a business case focused on return on investment or cash flows.

With specific reference to the Computerized Maintenance System, NTPC submitted that the existing maintenance control system has 3 fundamental issues:

- It is no longer supported by the software producer;
- It is no longer compatible with current computer operating systems; and
- It is limited in functionality in that it does not track any auxiliary equipment outside the main engines in a plant.

With respect to the electronic land use data base, NTPC identified the following benefits:

- Employees can quickly resolve property right issues with customers;
- Identify missing or unclear property rights;
- Ensure new distribution extensions have correct property rights;
- Reduced management time resolving property rights issues allowing management to concentrate on core functions;
- Increased customer service as property rights issues will be resolved in a timely manner. [NTPC Reply, P17-19]

With respect to expenditures on RTUs, NTPC stated that YK/HR appeared to misunderstand the distinction between capital spending and capitalization. When the Corporation spends money on an active capital project, the spending is captured in Capital Work in Progress ("**CWIP**"). These funds earn interest until such time as the project is completed and/or the assets become used or useful, at which time the spending is capitalized. Capitalized assets are built into rate base and amortized accordingly. RTU capital additions to rate base are provided in Schedules B-1 through B-4 of the Application, and total $2.7 million. Accordingly, while $3.4 million has been spent, only $2.7 million of this amount is proposed to be built into rate base, rather than the full amount as suggested by YK/HR. [NTPC Reply, P17, L9-16]

With respect to YK/HR's comments respecting business cases, NTPC stated that the framework for utility regulation in NWT already incorporates a provision for detailed review of project impacts on the business and on rates for all cases where a Major Project Permit is required under *the Act*. This threshold has been legislatively set at $5 million or 10% of a utility's rate base. NTPC submitted the legislation does not provide for any similar detailed project specific reviews for projects below this threshold. [NTPC Reply, P35, L6-10]

Board Findings:

The Board is concerned by the budget cost overruns on certain larger projects executed by NTPC, some of which are listed in BR.NTPC-28. This is particularly a concern given NTPC's acknowledgement of a breakdown in process checks and balances which resulted in inadequate planning and scoping of projects and incorrect budget estimates during the years leading up to 2009/10.

In the Board's view the existence of appropriate process checks and balances and accountability tools provide the necessary assurance that capital budgets reflect prudent cost estimates and accountability for actual project costs in relation to capital budgets. The Board notes NTPC's comments with respect to process improvements and accountability tools for performance it has recently instituted and is encouraged by the steps the Corporation has taken to address this issue. The Board expects NTPC to demonstrate the operation and effectiveness of these checks and balances as part of the testing of capital additions in future proceedings.

Given this context, the Board considers the preparation of business cases as described in Mr. Bell's evidence and in YK/HR Argument would facilitate assessment of capital forecasts in the context of a GRA and would also provide the necessary discipline for NTPC to ensure capital budgets and forecasts take into account the best available information having reviewed alternatives and that the capital budgets and forecasts are reasonably accurate.

Accordingly, the Board directs NTPC to provide business cases in support of major capital projects forecast to be added to rate base, at the time of the next GRA. The Board finds the list of items to be addressed in business cases as set out by YK/HR provides a reasonable template for structuring business cases. For the purpose of preparing business cases, the Board accepts YK/HR recommendation that the project cost threshold for business cases be set at $400,000.

NTPC is directed to prepare business cases for capital projects meeting the above threshold which are scheduled to commence after March 31, 2013 and should be prepared to provide detailed explanations for variances between budget and actual costs based on post completion reports.

The Board notes YK/HR's position that NTPC did not identify any tangible benefits to the land use data base project and computerized maintenance system its recommendation that the Board deny the inclusion of these projects in approved rate base. The Board notes NTPC has provided reasons for going ahead with these projects as well as the specific benefits associated with these projects. Therefore, the Board denies YK/HR's request to disallow these items from rate base.

With respect to YK/HR's request that RTU replacement be reduced to $0.8 million to represent the level of spending left in the project budget, the Board notes NTPC's explanation that the difference in spending referred to by YK/HR arises from not considering amounts included in CWIP. The Board accepts NTPC's explanation and will therefore not adjust the RTU additions for the Test Years.

3.3.2 Inuvik Diesel Conversion Project

NTPC indicated that the Inuvik conversion project is being undertaken entirely in response to the termination of natural gas availability for NTPC use. The project involves the conversion of two existing Wartsila engines (one 2.1MW and the other 2.8MW) to diesel use and, the installation of a 2.8 MW EMD diesel unit relocated from Jackfish. The project also involves upgrading and re-commissioning of the diesel fuel tank at Inuvik. NTPC states the re-commissioning of the fuel tank was under consideration for future years even absent the conversion of Inuvik to diesel, but must now be advanced to permit a base load diesel operation.

Although in its Application [Ex 2], NTPC estimated the cost of conversion of the two Wartsila units and relocation of the EMD unit to be $8 million, NTPC revised the $8 million estimate to $10.3 million in its update Application. [Ex 13] The proposed cost with respect to the Inuvik diesel conversion project is as follows:

Inuvik Diesel Conversion Project			
	2012/13	2013/14	Total
	$M	$M	$M
Conversion of 2 Gas Wartsila Engines to Diesel	7.7		7.7
One 2.5MW EMD Diesel Unit	2.6		2.6
Sub Total	10.3	0	10.3
Recommissioning Diesel Fuel Tank	2.3	1.2	3.5
Total	12.6	1.2	13.8

In Argument, NTPC stated that the Corporation's August 17, 2012 Major Project Permit application discussed a large range of options that NTPC investigated as potential solutions to address the firm capacity issues of the Inuvik Power Plant. Options that related to the use of synthetic gas (propane-air) to supply the existing gas units were ruled out as they are technically challenging, propane fuel (including storage) is very expensive and the use of propane is not recommended by the engine manufacturer. Options that solely focused on temporary solutions (e.g., rented modules) were not considered appropriate for a solution over potentially 5 or more years. [NTPC Argument, P32, L37 - P33, L5]

NTPC stated, the key option identified focuses on a solution that provides reliable power over a period of no less than 5 years (and potentially up to the full asset life of diesel units, in the event natural gas supply is not re-established in the future for the town). NTPC stated, the alternative option was also identified and discussed in conjunction with overall community planning efforts being led by the Town and the GNWT. [NTPC Argument, P33, L6-10]

NTPC stated that the effect of the capital project is equivalent to a major overhaul on each of the units, which will defer the schedule for overhauls. NTPC indicates it is estimating that the deferral effect will be roughly equivalent to avoiding one year of average annual overhaul cost for the Inuvik units, or approximately $1.1 million.

With regard to the third gas unit at Inuvik that is not proposed to be converted to diesel, NTPC's witness, Mr. Bowman, indicated there are potential future developments that are sufficiently on the horizon that one wouldn't necessarily want to rush to get rid of a gas engine in Inuvik at this point in time. [T160, L22 – T161, L1]

The TGC submitted it remains unclear to TGC why the failure in gas supply (which is the sole reason for this project) could not be predicted in a more timely fashion, if NTPC was in constant contact with the gas supplier. Further, the TGC stated it was not clear, given section 4.01(a) of the Gas Supply Agreement, whether the failure of gas supply for Inuvik may have had an economic component given the current turmoil in gas markets. [TGC Argument, P15, Para50]

In its Reply, NTPC confirmed its understanding that the loss of gas was unexpected and unforeseen and NTPC could not have completed any kind of meaningful analysis that would have prevented this situation from happening again. [NTPC Reply, P 9, L4-6]

Board Findings:

The Board notes the conversion of the gas units at Inuvik arose as a result of the imminent depletion of gas supply to the Inuvik plant. The Board accepts NTPC's forecast capital addition with respect to the Inuvik diesel conversion project for the purposes of this Decision.

The Board directs NTPC to provide a post completion report with respect to the Inuvik Diesel Conversion project at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in the planning, budgeting and execution of the project and, providing detailed explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant.

3.3.3 Bluefish Dam Replacement Project

NTPC forecast an addition of $37.398 million in 2012/13 with respect to the design and construction of a new dam at Bluefish Lake to replace the existing dam constructed in the early 1940s.

In Decision 20-2009, the Board approved the Corporation’s application for a project permit for replacement of the Bluefish Lake Dam in an amount up to $18.5 million. This budget estimate was later revised to $37.4 million plus or minus 10% in Decision 15-2011.

NTPC stated that the revised cost reflects the considerable time and effort NTPC spent in refining the project cost estimates and logistics. The revised cost incorporates changes in the project design resulting from more detailed investigation of the sizing of the water conveyance structures and the geotechnical conditions, as well as the results of the collaborative work with the selected contractor on cost saving measures and improvements in the new dam construction. NTPC noted that the project cost to date is within the updated approved budget of $37.4 million (+1- 10%) and the project implementation is on schedule.

Board Findings:

The Board is of the view that the Bluefish Dam is another project, in addition to those discussed in Section 3.3.1, where scoping and capital budgeting were not carried out with proper due diligence when the initial capital budget was prepared. This resulted in the revised budget estimate being more than double that in the initial budget.

The Board notes NTPC's statement that the project cost to date is within the updated approved budget of $37.4 million (+/- 10%) and the project implementation is on schedule.

Having regard to the Board's earlier acceptance of this budget in Decision 15-2011, the Board accepts NTPC's forecast capital addition with respect to the Bluefish Dam replacement project for the purposes of this Decision.

The Board directs NTPC to provide a post completion report with respect to the Bluefish Dam replacement project at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in the planning, budgeting and execution of the project and, providing detailed explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant.

3.4 Transmission Line Development Study

NTPC proposed to add $693,000 to the rate base in 2011/12 with respect to the cost of a transmission line development study carried out in the 2003-2005 period. NTPC indicates the study was not capitalized by NTPC until 2011/12 as up to this time the study had been considered “on loan” to NWT Energy Corporation (03) Ltd (“**NTEC(03) Ltd**”), an affiliate of NTPC.

NTPC indicated that the study looked at procedures and technologies that are appropriate to building transmission infrastructure in the NWT, as well as specific options and routing that would apply to a transmission line from the existing Taltson generating station to the North Slave diamond mines. NTPC stated that the commitment of $700,000 of regulated system capital investment ultimately enabled the following benefits for customers (both actual benefits, as well as further potential additional benefits had the project proceeded or if it proceeds in the future):

- *A new unregulated development company was formed (Northwest Territories Energy Corporation, 2003, or “NTEC(03) ltd.”) which was able to secure well over $5 million of government funding, at no cost to NTPC, with the largest component of this capital used for environmental studies at Taltson. These environmental studies were heavily relied upon by NTPC in its recent relicensing of the Taltson facility, and were specifically cited and provided for review by the Mackenzie Valley Land and Water Board (“MVLWB”). Absent the NTEC(03) ltd. environmental work, NTPC’s costs for relicensing the Taltson facility would have been substantially higher.*
- *At the time the studies were conducted, there was very little information to assess whether any business case could be developed for trying to market the 60 GWh of existing annual surplus Taltson power to the diamond mines. No reasonable cost estimate could be prepared for the transmission needed, and little information was known about the technological options, the routing options and the feasibility of such a project*

given challenging electrical characteristics related to long transmission lines at relatively low loading. Without such information no party could have moved the project concept forward. No project would ever have been developed without first "equity" being brought to the concept by NTPC.

- *The project had very high potential returns, given the scale of surplus power available. Even at a relatively low rate (as compared to the diamond mines' costs of diesel power) averaging, for example, at only 10 cents/kWh this would equal $6 million/year of new revenue with very little added operating costs. These revenues would have been available to help maintain lower rates for regulated ratepayers regardless as to the owner of the transmission line or any new generation.*
- *NTPC also expects ongoing value from the study, as it is the only updated assessment of the current best practices and available technology for transmission suitable for NWT. The conditions faced by NTPC in potential future transmission line construction are unique compared to southern utilities, and there was no updated information available specific to NWT.* [TGC.NTPC-49]

The TGC submitted that the study costs were incurred prior to the Test Years and thus are not proper capital for the Test Years. If the amounts benefited ratepayers as suggested by NTPC in cross-examination, NTPC should have forecast them in the rate applications applicable to the years it incurred the costs. NTPC did not receive prior approval of the Board to conduct these Capitalized Studies.

TGC submitted the Capitalized Studies related to utilizing excess capacity on the Taltson system, specifically for supplying electric energy to Diamond mines in the NWT. NTPC will not be the proponent of the project to which the studies relate. Rather, an unregulated affiliate of NTPC will ultimately gain the benefit of the Capitalized Studies and proceed with the project, likely with other private sector partners, as confirmed by Mr. Bowman in cross-examination. TGC submitted that many of the studies contained in BR.NTPC-23 were actually performed for parties other than NTPC, including Northwest Territories Energy Corporation, and Dèze Energy Corporation. The TGC submitted that the studies benefited other parties or unregulated affiliates of NTPC and as such, NTPC did not prudently incur the expenditures on the Capitalized Studies. On this basis the TGC submitted the capitalized studies should be denied in full.

TGC submitted that as a result of the proposed expansion project not proceeding, NTPC is now unable to recover the costs it expended on the Capitalized Studies from its unregulated affiliate which has resulted in it now seeking to recover these costs from customers, after the fact.

Furthermore, as NTPC does not have an approved deferral account for the costs related to the transmission line study these costs should be denied on the basis that approval of these costs would amount to retroactive ratemaking. [TGC Argument, P36, Para 128 – P38, Para 133]

TGC also argued that if the Board was inclined to accept any portion of the study costs, such costs should be allocated entirely to the Hydro Zone as no portion of the Taltson facility benefits the Thermal Zone. [TGC Reply, P4-5, Para 10]

In response to why the costs were not included in the period incurred, NTPC indicated that the study was loaned to the affiliate with an interest cost at prime less 50 basis points. Therefore, NTPC states spending on this study over that period of years was being compensated through that route. [T141, L9-16]

Board Findings:

The Board notes the primary purpose of the study was for the future transmission development to be undertaken by an affiliate of NTPC. The Board accepts that there may have been some anticipated benefits to NTPC's customers had the transmission development gone ahead. However, the benefit to NTPC does not appear to be the primary intent of the study. This finding is supported by the fact NTPC treated the study cost as a recoverable from NTEC (03) Ltd until 2011/12. Although the costs were incurred during the 2003-2005 period NTPC did not seek to include the cost in rate base even in the 2006-2008 GRA, but rather treated the amounts as a recoverable from NTEC (03) Ltd.

Since the primary purpose of the study was not related to providing electricity service to NTPC's customers, the Board denies the proposed inclusion of the study cost in the 2012/13 and 2013/14 rate base. Accordingly, NTPC is directed to remove the cost of the transmission line development study from each Test Year rate base, in its Compliance Filing Application.

3.5 Treatment of Capitalized Studies and Disallowed Assets Included in Plant in Service

The Board notes from Schedules 5.2 and 5.3 that the following amounts with respect to unamortized costs of feasibility studies are included in plant in service:

Feasibility Studies				
	2010/11	2011/12	2012/13	2013/14
Gross Plant	$000	$000	$000	
Beginning of Year	5179	5864	6557	6557
Additions	685	693		
End of Year	5864	6557	6557	6557
Accumulated Amortization				
Beginning of Year	4457	4702	5047	5379
Additions	245	345	332	332
End of Year	4702	5047	5379	5711
Net Plant	1162	1510	1178	846

The Board has dealt with the disallowance of the transmission line study addition in the amount of $693,000 in Section 3.4. This Section deals with the remaining costs included as unamortized costs of feasibility studies.

Board Findings:

With regard to the remaining costs included as unamortized costs of feasibility studies, the Board is concerned by the insufficient justification for inclusion of the cost of these studies in rate base and the amortization thereof in each Test Year.

In Decision 17-2007, Directive 18, the Board determined deferred cost items may typically include financing costs and any material costs incurred in conducting special studies. The Board noted in order for such expenditures to be considered eligible, NTPC should be able to demonstrate corresponding benefits that extend beyond a single year. Further, for deferred cost items that arise in non-test years the quantum of the expenditure proposed for deferred cost treatment should be material and NTPC should demonstrate why they are not considered part of the forecast variance in operations and maintenance expenses in that year. Accordingly, the Board directed NTPC to provide evidence showing how each item proposed for deferred cost treatment meets the conditions outlined above.

During hearing examination, NTPC's witness explained:

> *"..and that category is not one feasibility study, it's the sum gross plant total of all feasibility studies NTPC still carries on its books. And my recollection is many of those are even fully depreciated. But the full value of the study is on the books and the full value of the amortization is on the books, so it's a very long list of items. But one doesn't actually, the reason it's in the table, is one doesn't look at those studies and coming up with amortization and depreciation rate, they're fixed."* [T286, L15-25]

Given the lack of support provided during the proceedings with respect to the cost of feasibility studies (other than the transmission study) and the amortization thereof, the Board directs NTPC to provide as part of the Compliance Filing Application, details of all studies included under the category of feasibility studies and provide justification for why any additions to the feasibility studies account in the 2007/08 to 2010/11 period should be capitalized based on the guidance provided in Directive 18 from Decision 17-2009. At the same time, NTPC should also provide support showing how the amortization amounts in each Test Year were arrived at having regard to each study.

The Board also notes from Schedules 5.2 and 5.3 a category of costs referred to as disallowed and deferred regulatory assets included in gross plant in service and accumulated amortization as follows:

Disallowed and Deferred Regulatory Assets				
	2010/11	2011/12	2012/13	2013/14
Gross Plant	$000	$000	$000	
Beginning of Year	163	163	163	163
Additions	0	0	0	0
End of Year	163	163	163	163
Accumulated Amortization				
Beginning of Year	93	99	106	112
Additions	7	7	7	7
End of Year	100	106	113	119

The Board considers disallowed assets should not be included in gross plant in service and in rate base. Accordingly, NTPC is directed to remove the net book value of disallowed assets from Test Year rate base in its Compliance Filing Application.

The Board is concerned that inclusion of deferred costs under the category of deferral accounts and under the category of plant in service can result in confusion and errors in the testing and evaluation of such costs. Accordingly, NTPC is directed to include deferred costs under an appropriate FERC account at the time of the next GRA.

3.6 Major Spares and Capital Inventory

NTPC stated that net General Plant increases of $22.3 million in 2012/13 over 2007/08 reflect changes in accounting policy, which now includes major spare parts and capital inventory of approximately $6.7 million in the gross plant. NTPC further advised that the accounting policy change with respect to major spare parts and capital inventory is consistent with the accounting standard issued in 2007 by the Canadian Institute of Chartered Accountants ("**CICA**"). The Corporation's 2008/09 Financial Statement includes the following description respecting the change in accounting policy:

> As a result of adopting Section 3031, NTPC reclassified its major spare parts and standby equipment previously included in inventories to property, plant and equipment. As these inventories are considered plant held for future use, no adjustment to amortization expense or accumulated amortization has been made for these assets. Prior period comparative amounts were restated in accordance with the transition provisions. The inventories reclassified as at March 31, 2009 were valued at $685 (2008 - $524) and have been identified in Note 8 as Assets held for future use.

NTPC stated that the impact of the change is zero. NTPC confirmed that the proposed major spare parts and capital inventory approach involves no amortization costs for the 2012/13 and 2013/14 Test Years consistent with the above accounting policy. [TGC.NTPC-37]

The TGC expressed concern with the significantly higher dollar levels associated with spare parts and capital inventory. The TGC indicated that the $6.7M inventory is about 6 to 7 times higher than the average of about $0.6M in the 2008-2009 timeframe. With respect to NTPC's argument that diesel engines are "harder to spec", TGC submitted that NTPC had not filed any evidence to support the growth in such inventory. More specifically, it had not explained why the availability and increased magnitude of major parts and capital inventory had changed relative to the period prior to the change in its accounting policy in 2008/2009 to justify a significantly higher level of major spare parts and capital inventory.

The TGC also argued that there is no basis to use a change in GAAP as the exclusive rationale for a change in regulatory treatment. The TGC submitted the current Board-approved methodology has been in place for the last 20 years. The only difference between the current approved method and the proposed method is one of timing of cash flows. Under the existing Board-approved method, interest is capitalized and the inventory enters rate base at cost plus carrying costs (capitalized interest) when the inventory item is actually used or required to be used. The TGC submitted that the effect of NTPC's proposal is to build that carrying cost into rates today; such that it gets a cash return today as opposed to a "paper return" in the form of capitalized interest cost.

As such, the TGC recommended that the Board reject NTPC's proposed treatment and direct NTPC, in its Compliance Filing, to reflect continued adherence with the currently approved Board methodology. [TGC Argument, P18, Para 60 – P20, Para 66]

In its Reply submission, NTPC stated that the proposed method allows the Corporation to avoid maintaining two sets of financial statement records which would create a reconciling item and result in higher administration costs; and in the circumstances, given that the impact on the Revenue Requirement is zero, its proposed method is appropriate and should be approved. [NTPC Reply, P20, L9-13]

Board Findings:

NTPC explained that the increase reflects the holding in inventory of long delivery equipment items such as engines, transformers and breakers. NTPC explained that the inventory helps to avoid delays when replacements are needed and further helps to standardize the equipment that is installed. [T283, L4]

The Board notes TGC's argument that the $6.7M inventory is much higher than the average of about $0.6M in the 2008-2009 timeframe and NTPC has not filed any evidence to support the growth in such inventory. However, the Board is mindful of NTPC's position that the inventory helps to avoid delays when replacements are needed and further helps to standardize the equipment that is installed. The Board considers that NTPC has not provided any analysis that would weigh and evaluate the qualitative and quantitative benefits of holding the proposed level of inventory in relation to the carrying costs. In the absence of such evidence, the Board will approve the inclusion of 50% of the proposed inventory in rate base in 2012/13 and 2013/14. Therefore, NTPC is directed to remove 50% of the cost of major spares and capital inventory from Test Year rate base in its Compliance Filing Application.

If NTPC were to hold any portion of the disallowed inventory as plant held for future use, NTPC should be able to demonstrate the level of inventory on which Interest During Construction ("**IDC**") is being added is justifiable based on a cost benefit analysis as described above.

3.7 Customer Contributions

NTPC's forecast of customer contributions is shown in schedule 5.4.

The TGC requested that the 2012/13 Test Year opening balances for customer contributions be updated to reflect the 2011/12 actual closing balances. The Board will deal with this matter in Section 13 .1 of this Decision.

Under cross examination NTPC was asked why there are no additions to customer contributions included in 2011/12 to 2013/14.

In response, NTPC's witness indicated that when a new customer is connected there is a cost to connect that customer, some of which is paid for by the customer as a recoverable and some of which is paid for by the Corporation as a non-recoverable. The portion that's paid for by the customer as a recoverable cost is what's recorded as customer contributions. [T354, L16-22]

The Corporation explained that the non-recoverable portion is referred to as type 6 non recoverable work in the capital additions schedule and is largely comprised of distribution extensions that the Corporation undertakes when it adds customers to the system. NTPC indicated that customers do have an allowable investment that pays for a portion of that investment, but there's also a portion that's non-recoverable. And those would be capital assets that are being recorded in the capital additions schedule. [T233, L1-9]

Board Findings:

The Board accepts NTPC's explanation for zero contribution additions in the Test Years.

3.8 Working Capital

NTPC's calculation of working capital is set out in Schedule 5.6. Working capital is made up of cash working capital as well as fuel and supplies inventory. The cash working capital calculation is based on an analysis of leads and lags associated with operating cash payments and receipts.

NTPC states the revenue lag for industrial and wholesale customers was calculated from the billing date to the date the collection was actually deposited to the Corporation's account. NTPC stated that in order to establish the payment lag associated with bills rendered to customers whose bills are computer generated, a comprehensive analysis of all utility revenues billed and collected through the Corporation's billing system for the period under study was performed using a computer program.

As an alternative to the sampling approach to determination of revenue lag NTPC also calculated the revenue lag based on when payments by customers for bills rendered is due. This was described as the normalized approach. NTPC states, the normalized approach uses the NTPC approved Terms and Conditions of Service to develop the overall revenue lag. This same normalized approach is used for the calculation of the expense lag and the overall payment lag is based on the Corporation’s standard payment practices. NTPC states using the normalized approach for both revenue and expenses is appropriate as both calculations use the same normalized methodology. It would be incorrect to use a sampling methodology for the calculation of revenue and a normalized approach for the calculation of expenses.

The TGC submitted that the use of the sampling method results an increase in working capital lag by 9 days or $0.115M in Revenue Requirement ($1.651M increase in rate base times 6.94%). However, NTPC would also have to include Interest on overdue accounts of $0.153M as a revenue offset for a net reduction in 2012/13 and 2013/14 Revenue Requirement of about $0.038M. TGC submitted it does not oppose the continued use of the normalized approached as long as it is corrected for the amount of the Interest on overdue accounts. The TGC therefore recommend the Revenue Requirement be reduced by $0.038M in each of the Test Years. [TGC Argument, P31, Para 108 – P32, Para 109]

In its Reply, NTPC submitted TGC’s acceptance of the normalized method with an adjustment for the calculation of the revenue lag only is one sided and should be rejected by the Board. As noted, the Directive only reviewed the revenue lag variance and not the expenditure variance. Adjustments for only one component of the cash working capital calculation are incorrect. Further, in NTPC's view it would be incorrect to lower revenue requirement based on the normalized approach and then further lower it by interest on overdue accounts as it would produce a “double counting” of revenue which the Board should reject. [NTPC Reply, P21, L5-15]

Board Findings:

The Board understands NTPC's working capital calculation in these proceedings is based on a normalized approach for both payment lag and revenue lag. The normalized approach reflects the Corporation's standard practices for payment of expenses as well as terms and conditions for receipt of revenues. The Board views the normalized approach as a theoretical approach for determination of cash working capital requirements.

Performing a lead lag study based on a sampling of actual transactions would have the added advantage that the Corporation will be alerted to any material deviations in the number of days lead or lag from the normalized approach.

Management then has the ability to take corrective action respecting any unplanned leads and lags, as necessary. Accordingly, the Board prefers a sampling approach to the development of a lead lag study and the determination of cash working capital.

The Board directs NTPC to provide a cash working capital calculation based on a sampling of leads and lags at the time of the next GRA. This means any revenues related to late payment charges should also be included in other revenues.

The Board accepts NTPC's calculation of cash working capital and total working capital for the purposes of this Decision.

3.9 Deferral Accounts

3.9.1 Regulatory and Other Deferral Accounts

As described in its Argument, NTPC is proposing to decrease the annual appropriation for the Regulatory and Other Deferral Account from $0.672 million to $0.377 million per year in the 2012/13 Test Year and $0.376 million in the 2013/14 Test Year. The decrease is a result of NTPC's efforts to decrease the costs of filing a GRA, the benefits of regulatory reform and anticipated simplification of the review process.

Included as part of this deferral account are two new items – Enterprise Resource Planning ("**ERP**") and International Financial Reporting Standards ("**IFRS**") Conversion – that NTPC states meet the requirements for deferral cost treatment.

Enterprise Resource Planning

In 2010/11, a project was initiated to review the Great Plains system which is the core of NTPC's ERP system. The objective was to assess whether opportunities exist to optimize the system and increase effectiveness and efficiency throughout NTPC. The first phase of the project, which was completed in 2011/12 at a cost of $136,000, was a gap analysis of the building blocks in NTPC's ERP (e.g. general accounting, customer processing, procure to pay/supply chain, human resources/payroll, projects and operations) against leading practice and common utility practice. The second phase of the project, to be completed in 2012/13 at a cost of $308,000, will focus on organizational hierarchy and code block structure.

NTPC is proposing the total project cost of $444,000 be included in the Regulatory and Other Deferral Account to be amortized over 10 years starting in 2012/13. NTPC states that this project will provide long-term benefits.

In addition to the $444,000, the work completed to date has identified a Business Intelligence ("**BI**") tool, at a cost of $60,000, which would be a valuable addition in terms of maximizing the reporting capabilities of the system. NTPC states that the extra $60,000 will not be part of the deferral account – it will be treated as a capital project for 2012/13 and managed within the overall capital budget for 2012/13.

NTPC also states that any future improvements to the ERP will be assessed in terms of cost/benefit and the treatment of those expenses as current or deferred costs will be made in accordance with the principles established in the 2006/08 GRA.

In its Argument, TGC stated:

> *“The TGC has no position on whether or not the proposed $444,000 is reasonable or prudent. In our view, there simply is not enough evidence on the record to make such a conclusion. NTPC refers to the elimination of a "number of manual processes that are taking place" that will "allow us to spend less time collecting and inputting the data and more time analyzing the data and making good business decisions of that analytic, yet NTPC will not eliminate any FTC positions." The TGC questions why, if this project has the potential to provide additional data management and capabilities to make more informed business decisions, did such a project have to wait until the commencement of a GRA?*
>
> *Based on the foregoing, the TGC recommends the Board should deny the additional $60,000 additional amount noted by NTPC in respect of the Business Intelligence (BI) tool. It would appear that if NTPC had done an appropriate business case, it should have anticipated this additional expenditure. Limiting the total project cost to the $444,000 projected in this rate case will avoid the "scope creep" and exert the discipline necessary to control costs to the amounts initially budgeted. To this end, NTPC acknowledged it is willing to manage the Enterprise Resource project within the overall capital budget of $444,000 put forward in this GRA for 2012/13. While the TGC is not opposed to this project, the TGC recommends that (i) the maximum amount approved for this project should be no more than $444,000 forecast in this 2012-2014 GRA, and (ii) no portion of this cost should be deemed to be either part of a deferral account or deferred costs.”* [TGC Argument, P23, Para 78-79]

NTPC responded in its Reply:

> *“TGC takes no position on the reasonableness or prudence of NTPC’s proposed $444,000 Enterprise Resource Planning (“ERP”) process (a deferred cost), but recommends the Board deny the complementary Business Intelligence tool, an estimated capital cost of $60,000.*
>
> *This Business Intelligence capital project is not, in fact, part of the GRA proposal from NTPC. NTPC witnesses identified that this project would be undertaken, but that it would occur as a normal intra-year adjustment to the overall capital plan and that the GRA capital plan budget would not be increased for this amount.*
>
> *TGC also recommends the ERP cost should not be part of a deferral account or deferred cost. As TGC does not oppose the Enterprise Resource Planning project, but also does not want it included in a deferral account, this suggests the cost would need to be included in the Corporation’s Operations & Maintenance budget as an annual expenditure. The Corporation does not agree with this proposal as the ERP project meets the guidelines of a deferral account, and further the TGC approach would increase overall Revenue Requirement 1 and rate impact for customers.”* [NTPC Reply, P21, L20 – P22, L2)

Board Findings:

Given that the $60,000 for the BI Tool will be accommodated within the overall 2012/13 capital budget, the Board sees no reason to deny this expenditure.

As for the overall ERP project, the Board is satisfied that the project meets the criteria for treatment as a deferred cost and approves the inclusion of the $444,000 ERP project cost in the Regulatory and Other Deferral Account to be amortized over a period of 10 years beginning in 2012/13.

IFRS Conversion

The IFRS Conversion project is budgeted for $546,000 up to 2011/12 with amortization beginning in 2012/13 over 10 years. NTPC states that this project provides benefits that extend beyond the single year as the one-time IFRS conversion will apply to financial reporting in future periods.

Of the $546,000, $296,000 was spent in 2009/10 and 2010/11. The remaining $250,000 was to be spent in 2011/12 but with the 1 year delay in the switch to IFRS, the $250,000 will now be spent in 2012/13.

In its Argument, TGC stated:

> *"As discussed in Section 2.1 of this Argument, implementation of IFRS has now been deferred by a further 12 months to January 1, 2014, and the Corporation plans to adopt this deferral. NTPC confirmed that notwithstanding the additional year of deferral (to January 1, 2014), the total amount of $541,000 in respect of consulting fees is still a reasonable forecast. Further, it has not spent the $250,000 noted in the above table.*
>
> *In our submission, now that the Canadian AcSB has allowed entities with rate regulated operations a further 1-year delay to implement IFRS, the TGC recommends the $250,000 expenditure be further delayed from 2012/2013 to 2013/2014.*
>
> *Further, it is noted that NTPC takes the position that a 100% of these costs should be on account of the regulated operations as they comprise 99% of the "reporting for that corporate entity."*

> *The TGC submits it is inappropriate to deem 100% of IFRS conversion costs to regulated operations. While the unregulated operations may be rather limited at this time, it is possible they may become more sizeable at some future point and at that time such non-regulated entities will benefit from consulting and other related costs incurred with respect to IFRS conversion. To this end, the TGC recommends NTPC provide at the time of its Compliance Filing, the relative size of its unregulated operations (in terms of revenues, expenses, capital employed etc) in the last 5 years relative to the regulated operations. This ratio should be used to allocate the IFRS costs to regulated/unregulated entities."* [TGC Argument, P21, Para 68-71]

On the timing of the spending of the $250,000, NTPC responded in its Reply:

> *"TGC recommends the Board delay the $250,000 expenditure for the implementation of IFRS from 2012/13 to 2013/14. NTPC notes however that, Table 1 from BR.NTPC-26(b) shows the forecast $250,000 expenditure not in 2012/13 but rather in 2011/12. The Corporation will implement IFRS for external reporting in January 2014 which is in the second test-year of this Application. As such these costs will be incurred before the transition into IFRS reporting in the 2013/14 test year. Accordingly, if the Board delays the $250,000 expenditure, it should be delayed from 2011/12 to the 2012/13 and not 2013/14."* [NTPC Reply, P31, L27 – P32, L4]

On the matter of the sharing of IFRS conversion costs with NTPC's unregulated affiliates, NTPC stated:

> *"Further, TGC incorrectly concluded these IFRS implementation costs are for both regulated and unregulated entities. The costs are required as the Corporation transitions into IFRS and are comprised of external consultants that specialize in transitioning utility companies into IFRS. The services provided by the external consultants are strictly for the regulated entities and not unregulated entities. IFRS implementation costs for unregulated operations are not being charged to regulated customers. In the circumstances, the TGC recommendation that IFRS implementation costs be shared between the regulated and unregulated entities should be rejected."* [NTPC Reply, P32, L13-20]

Board Findings:

On the matter of the $250,000, the Board expects NTPC to spend this money in an appropriate and timely manner to meet the final IFRS implementation date, whatever that final date turns out to be. The Board sees no need to issue a direction on this matter.

Given NTPC's clarification that the IFRS conversion costs are solely to the benefit of the regulated entity and not NTPC's unregulated affiliates, the Board also sees no need to issue any direction on the matter of sharing the IFRS conversion costs.

3.9.2 Engine Overhaul Deferral Account

NTPC is seeking approval to increase the annual amortization of the normalized overhaul deferral account from an annual level of $1.693 million per year approved in the 2006/08 GRA to $2.936 million per year to reflect increases in the balance and in the forecasted ongoing costs of overhauls primarily in the Thermal zone. The $2.936 million is an annual increase of $1.243 million which breaks down into the zones as follows: an annual increase of $0.095 million in the Taltson zone, an annual decrease of $0.224 million for the Snare zone and an annual increase of $1.372 million for the Thermal zone. The increase in the Thermal zone is being driven by increased overhaul costs for the larger generating units in the zone.

In response to Undertaking 23, NTPC described the parameters of the engine overhaul deferral account as follows:

> *"Diesel Engine Overhaul includes labour and materials for planned major maintenance, based on operating hours. Overhaul requirements vary with engine size, speed, make and operating conditions and typically are required at 5,000 hour intervals for minor overhaul, 15,000 hours for top overhauls and 30,000 hours for major overhauls. Engine Overhaul does not include minor routine maintenance carried out on a day-to-day basis (daily, weekly, monthly or hours based).*
>
> *General Definitions (may vary with manufacturer):*
>
> - *Minor Overhaul - engine inspect, testing, tune-up, exchange turbocharger, lube oil/filters.*
>
> - *Top Overhaul - minor overhaul, replace heads, fuel injectors, water pump and fuel pump.*

> - *Major Overhaul - top overhaul, replace pistons, liners, connecting rods, oil pump, exchange oil cooler, clean aftercooler and inspect vibration dampers.*
>
> *Hydro Generating unit overhauls follow the same principle; that is they include labour and materials for planned major maintenance, as specified by the manufacturer or standard operating procedures."*

NTPC states, consistent with the above definitions replacement of certain components of an asset as part of an overhaul is intended to replace consumable components of the engine, and the costs would be included in the overhaul deferral account. There is no disposal. The specific component would still be maintained in the fixed assets continuity schedule, until the underlying asset itself reaches the end of its useful life, at which point the replaced component will be disposed of as part of the associated asset.

In its Argument, TGC raised 2 issues – the cost of overhauls for the 3rd gas engine and the escalation of costs for the Inuvik overhauls.

On the costs of overhauls for the 3rd gas engine, TGC stated:

> *"The TGC has concerns about the magnitude of the cost of overhauls. For example, over the 3-year period 2008/09 to 2010/11, the average overhaul cost of the third engine is some $0.515M. In comparison, the cost of the two other original gas engines amounted to $0.793M, or about $0.397 per year. The overhaul cost for the third gas engine, the newest of the three gas engines, is therefore on average some 30% higher [$0.515/0.397M] than the other 2 gas engines. No evidence is provided to suggest there is something unusual or different about the newest third engine which would require more costs to overhaul.*
>
> *As the newest engine, one would expect the overhaul costs to be similar to or lower than older gas engines. Nowhere is the higher expense more evident than in 2008/09, which is just two years after the third gas engine was installed in 2006/07. In this year, the newest engine cost $645,000, about $79,000 [$0.645-0.566M] or 14% more than the combined cost of the other two gas engines which were installed back in 2000, some 6-7 years previously. Another way to look at it is that the third engine at $0.645M cost some $0.362M, or more than double the cost (127% more) of the average of the other two gas engines of $0.283M.*
>
> *NTPC has not provided any evidence why the cost of the third diesel engine is so high relative to the other 2 gas engines. It is our recommendation, therefore, that the overhaul*

> *cost of the third diesel engine should be no more than the average cost of the other 2 diesel engines of $0.397M noted above. As such, the TGC recommends disallowance of $0.354M as shown on the following table:*

Calculation of Excess Overhaul Costs for the Third Gas Engine in Inuvik for the Years 2008/09 though to 2010/11

	2007/08	2008/09	2009/10	2010/11	2011/12	Total	
third engine	29	397	397	397	83	1,302	Deemed cost of $0.397M/yr for 2008/09, 2009/10 and 2010/11
original gas engines	839	566	938	876	349	3,568	
diesel engines	5	231	343			579	
total adds	873	1,194	1,678	1,273	432	5,449	
Reduction	-	(248)	185	(290)	-	(354)	

[TGC Argument, P25, Para 85-87]

NTPC responded in its Reply:

> *"TGC's argument in respect of the third gas engine includes a number of incorrect statements. In particular, TGC asserts that overhauls on the third gas engine are overly costly as they average $0.515 million compared to $0.793 million for the two older engines. TGC only arrives at this value by a selective interpretation of the data in Table 8 at page 24. Specifically, TGC ignores the year 2007/08 in calculating its long-term average numbers for no apparent reason. Had this year been included, the average costs for the third engine are almost identical to the costs per unit for the older 2 engines. As costs for overhauls are cyclical over a lengthy period that can be 5-7 years depending on the hours the units are used, the selective mathematics on 3 chosen years is an incorrect approach. Further, TGC notes that "No evidence is provided to suggest there is something unusual or different about the newest third engine which would require more costs to overhaul." NTPC would like to point out that, along with the clarification that the third gas engine has not been more costly, TGC did not put any questions to NTPC at the hearing to attempt to elicit any such facts about the third gas engine one way or the other."* [NTPC Reply, P22, L14-26]

On the matter of the escalation of costs for the Inuvik overhauls, TGC states:

> *"The underlying problem appears to be the manner in which NTPC's contract with the OEM was structured. More specifically, if the OEM failed to satisfy maintenance requirements, the contract could be terminated. However, NTPC agreed not to sue the OEM in the event the OEM failed to live up to the maintenance requirements under the contract. It is surprising that any prudent person would agree to let the party failing to live up to the contractual terms off "scot free".*
>
> *It is clear that NTPC experienced significant additional costs and expense as a result of the OEM not performing maintenance it was required to perform under contract with NTPC. NTPC now wishes to pass these additional costs to customers. In our view, had proper penalties for non-performance been built into the contract, NTPC would not have incurred the additional costs.*

NTPC should have laid out penalties in the contract for "failure to perform". Not having such penalties obviously provided an incentive for the OEM to act at will in terms of its responsibilities with respect to maintenance requirements for the two gas generating units. NTPC. The result, it appears, is an additional cost to customers of $2.246M shown in Table 8 of Exhibit 003, BR.NTPC-23 (g), page 14 of 15. In our view, this additional cost should be shared 50:50 with the shareholders. As such, the TGC recommend the Board disallow $1.123M from the Overhaul Deferral Account for Thermal Zone." [TGC Argument, P26, Para 90 – P27, Para 92]

NTPC responded in its Reply:

"The facts that are in evidence in this proceeding are that NTPC had a contract with the gas engine OEM that provided overhauls at a very favourable price compared to market. That contract led to many years of overhauls in Inuvik at a consistent price dating back to before the 2001/03 GRA. At a particular point in the life of that contract, the service provided by the OEM become inferior, and NTPC was faced with a choice between reduced reliability or terminating the contract. NTPC sought for a number of years to find alternatives within the contract to have the contractor increase their performance quality. In the end that was not possible, and NTPC elected to terminate the contract as reliable service to the customers in Inuvik was more critical than below-market pricing.

In short, TGC's argument is not based in fact, and should be rejected by the Board. The maintenance contract in place had a minimum annual price and was based on the power production subject to a 4% annual escalation factor. These favorable pricing terms benefited customers from 2001 to 2006 but were subject to a termination clause where neither party would be liable to the other after the termination date.

TGC suggests if "proper penalties for non-performance [had] been built into the contract, NTPC would not have incurred additional cost." This suggestion incorrectly assumes that the same fixed pricing terms could have been achieved even if the contract imposed adverse non-performance penalties. It is unknown and unrealistic to retrospectively assume the same pricing terms could have been achieved with adverse performance penalties for the OEM. The contract signed by the Corporation contained good pricing terms for the Corporation and customers but ultimately did not protect against poor performance. TGC further suggests the Corporation should have sued the OEM based on the terms of the contract. However, on the terms of the contract, neither party would be liable to the other after the termination date, and the Corporation could not sue the OEM for poor performance.

The Corporation was aware that the contract was beneficial to the customers and it wanted to maintain the contract. Accordingly, from 2004 to 2007 the Corporation met with the OEM on several occasions and tried to resolve the issues. For three years the Corporation tried to resolve the issues as any prudent person would do. TGC is incorrect when they suggest the Corporation let the OEM off "scot free" or that the Corporation was not prudent. While the pricing terms were beneficial, the Corporation could not continue to reduce the reliability of the engines. TGC suggestion that the maintenance contract should have continued fails to recognize that reduced reliability and increased outages ultimately result in greater harm to customers." [NTPC Reply, P23, L6 – P24, L5]

Board Findings:

On the matter of the cost of overhauls for the 3rd Inuvik gas engine, the Board shares NTPC's concerns about TGC's selective use of 3 years of data. The Board notes that if the 5 year period from 2007/08 to 2011/12 were taken together, the average annual cost of overhauls for the 3rd engine is $331,000, which is less than the annual average of $356,800 for the first 2 engines.

On the matter of the escalating cost of overhauls in Inuvik, it is the view of the Board that it will not, over a decade after the fact, question the contents of the maintenance contract for the first 2 gas engines. It is apparent that the contract provided benefits to the ratepayers for a period of time and those benefits later ran out. The Board expects that this incident will be a lesson learned for NTPC when it negotiates future maintenance contracts but the Board will not retroactively try to figuratively renegotiate the terms of this contract to make it more favorable to the ratepayers.

The Board notes NTPC's statement that the replacement of certain components of an asset as part of an overhaul is intended to replace consumable components of the engine, and the costs would be included in the overhaul deferral account. In the Board's view there is lack of clarity as to what the consumable components are. More specifically, the consumables should not include components that are considered retirement units for amortization purposes. The Board's understanding of the treatment of replacements that fit the definition of retirement units is that they are retired from gross plant and the cost of the replacement capitalized. The Board directs NTPC to address the appropriate treatment and adjustments for any expenditures for components included in the Engine Overhaul Deferral Account, that are considered retirement units for amortization purposes, in its Compliance Filing Application.

3.9.3 Water License Deferral Account

As a part of the 2006/08 GRA, NTPC applied to establish a water license deferral account with a normalized annual appropriation. The water license deferral account captures the cost of all water licensing activities including regulatory costs, environmental and dam safety studies and related activities. The Board approved the water license deferral account in Decision 13-2007.

In this Application, NTPC is applying to increase the annual amortization of the water license deferral account from an annual level of $0.137 million per year approved in the 2006/08 GRA to $0.751 million per year in 2012/13 and $0.825 million per year in 2013/14 to reflect material increases in the balance in the account and in the forecast level of effort and spending required to maintain and renew NTPC's water licenses including regulatory reviews, compensation, environmental and dam safety studies, Aquatic Effects Monitoring Program (AEMP) costs and all related activities (except capital works). The account mid-year balance is forecast at $5.109 million in 2012/13 and $5.094 million in 2012/13.

A major component added to the deferral account is $3.2 million of Taltson re-licensing work that consisted of various studies that were used during the re-licensing process.

Regarding the $3.2 million spent on studies used during the re-licensing process, the TGC stated the following in its Argument:

> *"The TGC submits that capital additions related to the $700,000 transmission line development study and the $3.5 million in studies capitalized to the Talston re-licencing account totaling 4.2 million ("Capitalized Studies") should be denied in full."* [TGC Argument, P36, Para 127]

The TGC's explanation for this position is somewhat unclear as the TGC seems to be treating the $3.2 million on environmental studies and the $700,000 on the transmission line study the same in some places and differently in other places. The Board is of the view that TGC's argument would have been easier to follow had it discussed these issues separately.

The basis of the TGC's position on the $3.2 million appears to be that 1) these studies were completed in previous years and so it would be retroactive ratemaking to capitalize them now; and 2) the studies were initially conducted for other parties and so should not now be paid for by NTPC's customers.

NTPC responded in its Reply:

> *"On the first of the two items listed, the $3.2 million of Taltson Water Re-licencing costs, these costs were incurred by NTPC and performed by NTPC as a required component of re-licencing the Taltson dam. The re-licencing process was successful and NTPC is now in possession of a renewed water licence that permits it to operate the dam for the benefit of ratepayers. There is no alternative interpretation but that these studies are used, useful, and required to provide service to ratepayers in the test year period.*
>
> *…*
>
> *The irony of TGC's argument is that one of the reasons they cite for its recommendation to deny the $3.2 million is that many of the studies contained in BR.NTPC-23 were performed FOR parties other than NTPC. TGC fails to understand the evidence that the studies they are citing, over $10 million worth, were performed and paid for BY parties other than NTPC, but NTPC (and its ratepayers) still received the benefit of these studies as part of its re-licencing application. None of this $10 million in studies is proposed to be included in rate base.*
>
> *Had NTPC not triggered the initiation of the Taltson expansion program, it is expected that a substantial portion of the $10 million in work that ratepayers are presently benefitting from (at no direct cost) would have had to be performed in any event, ultimately leading to higher rates to the Taltson zone than those required in the current GRA."* [NTPC Reply, P27, L23 – P28, L10]

Board Findings:

The Board has no evidence to suggest that the ratepayers are not receiving full value for the forecast $3.2 million in environmental studies used for the Taltson re-licensing. Moreover, the Board notes that NTPC has provided compelling evidence that the studies are used and useful and necessary to provide service. The Board also notes that YK/HR, representing the Taltson Zone, did not comment on the study costs. Accordingly, the Board approves the addition of the environmental study costs related to Taltson re-licensing to the deferral account in 2011/12 and does not consider this to be retroactive ratemaking.

3.9.4 Reserve for Injuries and Damages

In its Application, NTPC stated:

> *"In the 2006/08 GRA consistent with previous GRA's the Corporation included the annual appropriation to the Reserve for Injuries and Damages account as part of its Operations and Maintenance expense. In this GRA to be consistent with other annual deferral provisions the Corporation is including the appropriation in amortization of deferred charges instead of Operations and Maintenance expenses. In the 2006/08 GRA, the Reserve for Injuries and Damages was included as no-cost capital. Subsequent to the 2006/08 GRA, these accounts are no longer sources of capital and are in positive balances owed to the Corporation. As the Reserve is no longer a source of capital it is moved into the deferral accounts portion of Rate Base."* [Ex 2, P5-13, L6 – 14]

NTPC is seeking approval for a continuation of the Reserve for Injuries and Damages ("**RFID**") at the same $0.670 million per year appropriation approved in the 2006/08 GRA.

In its Argument, the TGC stated:

> *"The RID balance forecast at March 31, 2014 is $0.851. Hence, at an annual amortization of $670,000, and based on NTPC's evidence it does not expect any further additions/events to the RID Account. The TGC notes the RID balance will be in an over-funded in 2 years,…*
>
> *…*
>
> *The TGC submits that the funding amount should be such that on a forecast basis, the balance should be zero over the course of the 4-year transition period ending 2015/16 for*

> *rates proposed by NTPC in this Application. The TGC therefore recommends reduction in the RID amortization expense in each year by $122,000,…*
>
> *…*
>
> *The TGC makes the observation that in the case of the Employee Future Benefits Deferral Account, NTPC has proposed the 2012 balance be collected (i.e. the "catch-up" amount) over a period of 10 years. A similar approach has been taken for brushing expense. Using such an approach for the RID would result in an amortization of $0.219/year i.e. the 2012 balance of $2.191M/10 years. To be consistent with these other deferral accounts, the TGC submits the Board could, as an alternative to the recommendation noted earlier i.e. a 4-year amortization, reduce RID amortization costs from $670,000 to $219,000 for each of the Test Years."* [TGC Argument, P27, Para 95 – P28, Para 97]

NTPC responded in its Reply:

> *"The Application does not include any forecast additions to the RFID account. However this does not mean the Corporation will be protected from events that would meet the criteria of the RFID policy for the eventual inclusion in the RFID Deferral Account. For example, in the hearing, the Corporation discussed the flooding of Nahanni Butte which occurred after the Application was filed. At the time of the hearing the Corporation was still investigating the total damage and the costs were being tracked by a separate code. Once the total costs are known the Corporation may apply the costs to the RFID account if the event meets all the criteria of the policy. Based on the forgoing, TGC incorrectly concludes there is no future requirement for a "keep up" portion of the RFID account.*
>
> *Using TGC's approach and to be consistent with the other deferral accounts, the RFID account should have a catch up portion and a keep up portion. As suggested by TGC, with a 10 year amortization the catch up portion would be $0.219 million per year. Similar to the overhaul keep up, the RFID keep up would be based on the annual expenditures over a certain time period. Table 11 from BR.NTPC-23 shows the total charges to the RFID account of $2.944 million over a 5 year time period from 2007/08 to 2011/12. This is an annual keep up of $0.589 million. Under the TGC approach to be consistent with the other deferral accounts, the RFID amortization would be $0.808 million ($0.219 million + $0.589 million).*
>
> *The Corporation does not agree the annual RFID amortization should be increased to $0.808 million. Nor should it be decreased to only a catch up portion, given that external events such as the Nahanni Butte situation will continue to occur. The Corporation recommends that it be maintained at the approved level of $0.670 million."* [NTPC Reply, P24, L16 – P25, L4]

Board Findings:

While there are no forecast additions to the RFID, it is the Board's view that setting the annual appropriation based on there being no additions would not be prudent. The Board is satisfied with continuing the RFID with the current annual appropriation of $0.670 million. If the RFID ends up in an over-funded position the Board expects the Corporation to come forward with a suitable adjustment at the next GRA.

3.9.5 Employee Future Benefits

NTPC is seeking approval for a new annual amortization of $0.348 million per year to begin to discharge the balance in the regulatory Employee Future Benefits deferral account. The account has previously had no annual accrual pending a full drawdown of the balance that was established in the 2001/03 GRA, which has now occurred.

No parties submitted comments on the Employee Future Benefits deferral account in Argument or Reply Argument.

Board Findings:
The Board approves the new annual amortization of $0.348 million for the Employee Future Benefits deferral account.

3.9.6 Brushing Deferral Account

NTPC proposed the establishment of a Brushing Deferral Account, based on the principles of deferred costs. NTPC states brushing costs incurred each year will be deferred over 10 years starting 2011/12, leading to annual amortization costs of $0.132 million by 2013/14.

TGC submits, contrary to NTPC's Argument that brushing expenses provide some type of enduring value, these costs are not similar to capital assets which have a life of more than one year and can be said to provide some enduring value. The TGC submits NTPC's brushing proposal advanced in this GRA should be rejected.

The TGC stated, based on the history of brushing expenses provided in TGC.NTPC-44 (a), the average actual brushing costs for the period 2007/08 through to 2010/11 amounts to $0.306M. TGC submitted an appropriate forecast for the Test Years should reflect the actual brushing expenses incurred in the last few years. NTPC is free to manage its brushing program within the budgeted costs, without a need for true-up. Accordingly, the TGC recommended the Board reduce the forecast brushing expenses from $0.444M to $0.306M, a reduction of $0.138M for each of the Test Years 2012/13 and 2013/14. [TGC Argument, P29, Para 101- P30, Para. 102]

In its Reply submission, NTPC states recent past practice (including past averages) is not a good indicator of the future requirement for brushing, or for the expected individual annual level of brushing expense in any given year. Starting from 2010/11, NTPC implemented a higher level modern brushing program with average annual cost exceeding $0.400 million. This estimate is based on the review of actual competitive tender pricings and the expected required scale and frequency of brushing work to be completed on NTPC’s transmission and distribution lines.

NTPC submits, past history gives no evidence of the required future level of activity and the scale of spending in any zone is “lumpy”. In addition, there should be no debate that brushing expenses are similar to capital assets in terms of providing enduring value, because brushing in any particular area will only be done on either a 6, 10 or 20-year cycle. Implementation of a deferred treatment for brushing expenses would result in smoothing out of the year to year fluctuations in actual expenses. NTPC submits the TGC's proposal would not provide a reasonable matching of costs with the rate periods in which they provide benefits, and would not promote rate stability. [NTPC Reply, P25-26]

Board Findings:

The Board recognizes the treatment of brushing expense as a deferred cost can result in smoothing out the lumpiness of these expenditures by zone. However, the Board is concerned that treatment of brushing on a deferred cost basis takes away the incentive to be efficient in terms of the scope and type of the brushing programs and the corresponding costs. The Board agrees with the TGC that NTPC is free to manage its brushing program within the budgeted costs, without a need for true-up. Accordingly, the Board is not prepared to approve NTPC's request for deferred cost treatment of brushing costs.

The Board directs NTPC to include, in its Compliance Filing Application, annual brushing costs for each zone based on the 5 actual year average brushing costs with due adjustment for inflation and any forecast scope changes.

3.10 Conversion to International Financial Reporting Standards

NTPC states, in February 2008, the CICA Accounting Standards Board ("**AcSB**") confirmed that the transition to IFRS from Canadian GAAP would be required for publicly accountable entities for interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011, and would include comparatives for fiscal periods beginning on or after January 1, 2010. NTPC states, in July 2010, the AcSB proposed (and subsequently approved), a one year implementation deferral for rate-regulated entities. As such, the Corporation will be required to issue its first IFRS financial statements in fiscal year ending March 31, 2013 with comparative figures for the year ending March 31, 2012. NTPC indicates the conversion project is on-going and includes determining the key accounting differences between Canadian GAAP and IFRS as well as finalizing and implementing changes in policies and procedures throughout the Corporation to comply with IFRS.

Exhibit 21, response to Undertaking #1, indicates the AcSB has decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2014.

The TGC noted NTPC's acknowledgement that for both financial accounting purposes as well as for regulatory accounting purposes, NTPC will elect to take the deferral of IFRS changeover until such time as it is in a position where there are no further deferrals available. The TGC submits, notwithstanding the decision to defer the implementation of IFRS to January 1, 2014, for financial accounting and regulatory purposes, NTPC has decided to adopt certain aspects of accounting prescribed by IFRS.

In this regard, the TGC states NTPC is applying an IDC charge to capital projects based solely on the embedded cost of long-term debt. This means that, in effect, a portion of the Corporation’s long-term debt is not available to finance general rate base (i.e., assets in service) as it is applied as a “first call” against assets under construction. In 2013/14 the average cost of capital under the IDC “first allocation” of long term debt, versus the Allowance for Funds Used During Construction (“**AFUDC**”) approach of equally distributing equity and debt is less than 1 basis point (average cost of capital changes from 6.530% to 6.537%) or about $0.020 million on the overall revenue requirement.

The TGC recommended that the Board reject the proposed change over to IDC in light of the deferral of the implementation of IFRS to January 1, 2014 adopted by NTPC and in light of the immaterial impact of the proposed change as noted above. [TGC Argument, P4, Para 9]

In its Reply submission, the TGC stated IDC charges debt only, whereas AFUDC requires the calculation of the average cost of debt and equity. As equity generally has a lower cost than debt for NTPC, the AFUDC cost is lower than the debt cost alone. Further, as NTPC has applied for a nil cost of equity for the Thermal Zone and augmented the interest cost by 50% according to the GNWT Guidelines, the resulting IDC cost for the Thermal Zone is significantly higher than that for the Hydro Zone. The TGC submits the Board should deny NTPC's proposal to adopt IDC in view of higher carrying cost capitalized to assets under construction in the Thermal Zone relative to those under construction in the Hydro Zone. [TGC Reply, P5, Paras 12-14]

The TGC also submits that any potential changes arising from the adoption of IFRS, including (Deferral Accounts, Deferred Costs, Asset Retirement Obligations, Future Removal and Site Restoration Costs and PPE) should not impact or affect the accounting for rate making purposes. As such, the TGC recommends the Board direct NTPC that the adoption of IFRS for external financial reporting purposes will not automatically drive the requirements for rate making purposes on the basis that the methods used by the Board to establish just and reasonable rates have not always been the same as those used for external financial reporting purposes. Rather the methods used by the Board have been based on historical, sound regulatory principles. [TGC Argument, P7, Para 21]

In its Reply submission, NTPC notes that the TGC's disagreement respecting IDC is with the timing of implementation rather than the treatment of IDC. NTPC submits, by adopting the IDC approach and implementing it in 2012/13, the Corporation is able to avoid two sets of asset databases which would create a reconciling item incurring higher costs and administration. With an implementation in 2012/13, the Corporation also avoids an application to the PUB in the very near future concerning the AFUDC/IDC methodology. [NTPC Reply, P32, Para 22-29]

Board Findings:

The Board notes, as a result of the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities, the Corporation will be required to issue its first IFRS financial statements in fiscal year ending March 31, 2014. While further deferrals may be possible this is the current position of the AcSB and the target NTPC is working towards. Noting the relatively minor impact of the adoption of IDC in 2012/13, the Board will not require NTPC to defer the implementation of IDC from 2012/13 to 2013/14.

The Board considers, with the adoption of IDC, the interest rate used to calculate IDC on construction work in progress for each Zone will be the embedded cost of debt for that Zone. Accordingly, IDC that is capitalized as part of the cost of certain capital projects should not be impacted by the 1.5 interest rate multiplier applicable only to the calculation of return on rate base for the Thermal Zone.

The Board agrees with the TGC that any potential changes arising from the adoption of IFRS (including Deferral Accounts, Deferred Costs, Asset Retirement Obligations, Future Removal and Site Restoration Costs and PPE) should not necessarily impact or affect the accounting for rate making purposes. The Board will continue to require NTPC to maintain its regulatory records in accordance with regulatory principles. To the extent there are any differences between regulatory treatment and accounting treatment of items, there could be potential increases in the cost of administering two sets of records. NTPC should take these matters into consideration when transitioning to IFRS.

4. RETURN ON RATE BASE

4.1 Rate Policy Guidelines and Adoption of IDC

NTPC indicates it has revised its approach to determining the cost of capital in this GRA as compared to past practice. NTPC states the Rate Policy Guidelines introduced a new reserve margin concept for the thermal zones. Using this approach, NTPC no longer seeks a return on its shareholder's equity from assets in the thermal zone. Rather, NTPC only seeks to recover the cost of debt in this zone, plus a reserve margin (measured as 1.5 times "interest coverage" ratio, which indicates the degree of flexibility NTPC has to meet its interest obligations due to variability in operating results).

To give effect to this policy, NTPC states it is necessary to divide the rate base between the two groups (thermal zone and all non-thermal) to apply the appropriate cost rates to each balance. NTPC states in order to give full effect to this zoned approach it is also applying the cost of the Snare-Cascades hydro lease against the non-thermal assets to reflect the role it plays in financing rate base.

NTPC states it is applying an IDC charge to capital projects based solely on the embedded cost of long-term debt. This means that, in effect, a portion of the Corporation's long-term debt is not available to finance general rate base (i.e., assets in service) as it is applied as a "first call" against assets under construction.

The revised approach to calculating the Corporation's return on rate base is set out in Schedule 3.5. Sources of financing specifically related to certain components of rate base are addressed first including (long-term debt to finance work-in-progress, and capital lease to be applied 100% to non-thermal assets), leaving "general" capitalization (debt and equity) to finance the remaining components of rate base. The calculation of return on rate base for the non-thermal assets includes provision for debt, equity and the capital lease.

Board Findings:

The Board notes the assignment of the Snare Cascades capital lease to non-thermal rate base results in a debt to equity split of 61:39 for the non-thermal zone and 57:43 for the Thermal Zone. This means the debt interest subject to the 1.5 multiplier would be lower than would be the case if the 60:40 debt equity capital ratio, applicable to NTPC overall, were applied to the Thermal Zone. The Board notes the higher debt ratio (61% versus 60%) for the non-thermal rate base was necessitated by the need to assign the capital lease to the non-thermal rate base. Taking this into consideration the Board accepts NTPC proposed method of calculating the return on rate base to comply with the Rate Policy Guidelines and to reflect the transition to IDC as set out in Schedule 3.5.

4.2 Capital Structure

NTPC proposed a capital structure reflecting the financing of NTPC's rate base by approximately 40% equity and 60% long-term debt and capital lease, for 2012/13 and 2013/14.

Board Findings:

The Board notes NTPC's proposed capital structure together with a rate of return on equity of 8.5% on non-thermal rate base results in an interest coverage ratio of 1.69 in 2012/13 and 1.76 in 2013/14 as shown below:

Interest Coverage Ratios		
	2012/13	2013/14
	$000	$000
Debt Interest-Thermal Including Reserve	4682	4309
Debt Interest-Thermal	3121	2873
Debt Interest-Non Thermal	6285	6253
Interest on Capital Lease	1908	1869
Total Interest	11314	10995
Total Return	19111	19337
Interest Coverage Ratio	1.69	1.76
Source: Schedule 3.5		

The Board notes that the above ratios may change slightly following NTPC's update filing in Exhibit 13, which reflects a lower cost of debt.

None of the parties commented on the proposed capital structure. The Board considers the proposed capital structure and resulting interest coverage ratios are not unreasonable considering that NTPC's past coverage ratios were in the range of about 1.7. [Decision 13-2007, P32] Accordingly, the Board accepts NTPC's proposed capital structure for the purposes of this Decision.

4.3 Cost of Capital

In its Application, NTPC forecasts the issuance of long term debt in the amount of $25 million in 2012/13 at a coupon rate of 4.29%. In its update filing, NTPC indicated this $25 million debt will be issued at the interest rate of 3.818%, which will lower the cost of debt to the benefit of ratepayers. [Ex13; P3] As a result, the Mid-Year Cost of Long-Term Debt was revised to 6.47% and 5.68% in 2012/13 and 2013/14 respectively in Exhibit 13.

Consistent with the Rate Policy Guidelines, NTPC proposes a Return on Equity (‘**ROE**”) in the Thermal Zone of 0%. In place of an ROE for the Thermal Zone, NTPC proposed to increase the cost of debt by a multiple of 1.5 in order to provide an interest coverage ratio of 1.5.

For all assets outside the thermal zone, NTPC proposed an ROE of 8.5%. NTPC indicates the 8.5% ROE was determined on a simplified basis. NTPC states, the requested rate is below market standards recently set for utilities in Canada, such as the 8.75% low risk benchmark approved by the Alberta Utilities Commission for lower-risk large southern electric utilities (2011 and 2012 and interim 2013), and the 9.3% approved for Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited (collectively “**Northland**”) (2011, 2012, and 2013).

During cross examination, Board staff questioned NTPC with regard to why the average rate of return on sinking fund investments during the Test Years are forecast to be less than the rate of return in prior years. In response, NTPC indicated the number of debt instruments with sinking fund requirements is decreasing. Considering the long term nature of the debt, NTPC states, the Board of Directors have elected to amend the sinking fund policy allowing management only to invest in fixed income type investments which results in lower earnings. [T301; L15-20]

Board Findings:

The Board accepts the 8.5% ROE applicable to the equity portion of non-thermal rate base as it results in an acceptable interest coverage ratio for the Corporation in each of the Test Years as discussed in Section 4.2. The Board also accepts NTPC's proposals respecting the cost of debt.

In BR.NTPC-7b), NTPC provided a detailed cost of debt calculation. NTPC is directed to file the calculation of the updated cost of debt (as updated in Exhibit 13) in the same format as in the BR.NTPC-7b) attachments, in Excel format, in support of its Compliance Filing Application.

4.4 Capital Lease

In 1996 the NWT Energy Corporation Ltd. ("**NTEC**"), pursuant to the authority of the Northwest Territories Power Corporation Act, financed the construction of a 4.3 MW hydro facility by the Dogrib Power Corporation ("**DPC**") [Ex 22; P19]. NTPC then leased the hydro facility from DPC under a 65 year lease agreement.

In Decision 13-2007 the Board noted that the capital costs that the Corporation incurs with respect to the lease represent DPC's costs of financing comprised of DPC's cost of debt raised to finance the construction of the project (9.6% on 93.26% of DPC's capital structure) and a return on DPC's equity position in the project (NTPC's allowed return on equity less 0.25% on 6.74% of DPC's capital structure). [Decision 13-2007; P 26]

DPC's cost of debt financing, in turn, reflects the actual cost rate of borrowing from NTEC an amount of $22.9 million under a loan agreement between the two parties. To provide the debt financing to DPC, NTEC issued three series of debentures as follows:

Date of Issue	Amount of Issue	Due Date	Coupon Rate
May-95	$8 million	May-25	10.00%
Oct-95	$8 million	Oct-25	9.75%
Sep-96	$9 Million	Sep-26	9.11%

In Decision 13-2007, the Board noted that DPC's cost of financing the lease is based on 93.26% debt owed to NTEC at 9.6% interest which is being repaid over 30 years and 6.74% equity at the allowed rate of return on equity minus 25 basis points. Further, the Board noted that given the mismatch in cash flow profiles, there may be potential for DPC to reduce its cost of capital by substituting some of the higher cost debt included in its capital structure with lower cost debt as the 9.6% debt is being amortized over 30 years.

Accordingly, the Board directed NTPC to address the potential for better matching the carrying cost of the lease to DPC with the cost of the lease to NTPC over the 65-year term of the lease, at the next GRA.

In response to this direction, NTPC states the matter of DPC's cost of financing is beyond the control of NTPC. As the lessee, NTPC's rights and obligations are set out in the lease agreement with DPC, which includes compensation to DPC for their costs related to financing the assets. DPC arranged for long-term financing in the late 1990s at market rates then applicable to long-term borrowings and this debt has been the underlying basis for calculation of the lease costs since that time (including approval by the Board for inclusion of these costs into rates). Given that DPC's debt is structured as long term debt, the same rules apply to NTPC long-term debt; that is, the rates cannot be readily adjusted and cannot be retroactively tested for reasonableness without recognizing the alternatives that existed at the time (including the lack of options for 65 year fixed-rate financing). [Ex 2; P6-7]

Board Findings:

The Board notes the repayment of the loan to NTEC by DPC would be over a 30 year period whereas the lease obligation spans a period of 65 years. Consistent with this difference in timing of payments, the balance of the loan payable by

DPC to NTEC is $18.191 million as of year-end 2011/12. [Exhibit 22, Note 13 to the 2011/12 Annual Report] while the lease obligation, on which interest is being calculated by NTPC, shows a balance of $20.036 million as of year-end 2011/12. [Schedule 3.6]

Since the loan to NTEC is being paid at a faster rate than the 65 year term of the lease obligation, it would appear that DPC's cost related to the financing of the hydro facility lease may be changing since the time the initial terms of the lease were negotiated. In effect the faster repayment of the loan by DPC to NTEC would provide DPC the opportunity to substitute the high cost debt with lower cost debt at current borrowing rates in order to finance the lease.

While the Board does not consider it appropriate to test the reasonableness of the initial rates for financing that were negotiated, the Board notes the understanding at the time of the last GRA that the capital costs that the Corporation incurs with respect to the lease would represent DPC's costs of financing comprised of DPC’s cost of debt raised to finance the construction of the project (9.6% on 93.26% of DPC’s capital structure) and a return on DPC’s equity position in the project. In view of this the Board considers that any change in DPC's cost of capital with respect to its financing of the lease over the 65 year term, should be reflected in customer rates. The intent of the Board's Directive 25 in Decision 13-2007 was to elicit a full discussion and estimates of any changes in DPC's cost of capital.

Having regard to the cost based nature of the lease; the Board is not persuaded by NTPC's statement that the same rules apply to the lease as for NTPC's long-term debt. The Board is also not persuaded, based on the evidence filed, why changes in DPC's cost of financing over the 65 year lease term may not be reflected in the lease rates paid by NTPC.

Accordingly, the Board directs NTPC to provide, at the time of the Compliance Filing Application, evidence to support NTPC's view that the same rules apply to the lease as for NTPC's long-term debt and to provide evidentiary support for the view that DPC's cost of financing over the 65 year lease term should remain unchanged, notwithstanding the cost based nature of the lease.

5. PRODUCTION FUEL AND PURCHASE POWER

In its September 19, 2012 update, NTPC revised its 2012/13 and 2013/14 production fuel forecasts. The 2012/13 forecast was increased by $280,000 to $24,824,000. The 2013/14 forecast was increased by $293,000 to $25,194,000. These two increases are due to the original fuel price forecasts in the application being updated to reflect the actual August 2012 fuel prices from the Petroleum Products Division, which are approximately 1 cent/litre higher on average than in the application.

The September 19, 2012 update did not change the purchased power forecasts of $2,993,000 for 2012/13 and $2,978,000 for 2013/14.

Interveners raised concerns with fuel efficiencies and the Inuvik gas situation. Each topic is addressed in the following sections.

5.1 Fuel Efficiencies

In Argument, TGC recommended that NTPC be required to amend their method of forecasting fuel efficiencies when a new diesel engine is being installed in a community. TGC stated:

> *"The TGC does not object to the 3:2:1 ratio approved by the Board in prior rate cases. However, in order to avoid the deferral of improvements of fuel efficiencies in the Test Years to some future years beyond these Test Years, this ratio needs to be tweaked slightly. Where in a Test Year NTPC is forecasting the installation of a new engine to be installed in a particular community, the result of which is an improved overall fuel efficiency for that community, NTPC should be directed to reflect that fuel efficiency in the determination of the fuel heat rates."* [TGC Argument, P33, Para 116]

NTPC responded in its Reply:

> *"NTPC readily acknowledged that the new diesel engines, scheduled to be installed during the test years in Nahanni Butte and Jean Marie River, would be more efficient than the historic efficiencies. However, there is no viable means of forecasting the efficiency improvements.*
>
> *In the 2006/08 GRA, the issue of forecasting efficiency changes due to engine installations was extensively discussed in regards to the third Inuvik gas engine. The manufacturer's fuel efficiency ratings were examined as a means of forecasting efficiency improvements. These were largely ruled out as a viable proxy for GRA forecasts. As Mr. Kerr noted, manufacturer's ratings "…are based on one (1) hour of continuous operation at those loads, but it does not take into consideration any fuel consumed to warm up or cool down the engine." These ratings do not reflect real world conditions which a GRA forecast is intended to mirror as part of cost causation.*
>
> *The resulting Board direction was prefaced on the generally upward trend in fuel efficiencies and the Board's concern that customers could forego a year's worth of fuel efficiency improvements if the test years forecast were not included within the 3-2-1 calculation. The Board's direction sought to provide an equitable means of forecasting test year fuel efficiencies improvements and NTPC followed the Board's direction in preparing its 2012/14 GRA.*
>
> *The Corporation submits that its fuel efficiency forecasts for the test years are reasonable and should be approved."* [NTPC Reply, P8, L3-20]

In its Reply, the TGC stated:

> *"The TGC recommendation that the Board should tweak the application of the 3-2-1 method to reflect the improved fuel efficiencies arising from a new engine installation is fair, and will result in a forecast of fuel costs more representative of the expected conditions. To this end, the Board should direct NTPC in its refiling to re-calculate the fuel efficiencies for the Test Years in each of the communities, including Inuvik, where NTPC forecasts a new engine installation.*
>
> *Where in a Test Year NTPC forecasts the installation of a new engine in a particular community, which results in an improved overall fuel efficiency for that community, NTPC should be directed to reflect that fuel efficiency in the determination of the fuel heat rates."* [TGC Reply, P4, Para 7-8]

Board Findings:

Attachment BR.NTPC-4(a-c) indicates that fuel costs are calculated at the community level using an average fuel efficiency rate for each community. Therefore changes in the fuel efficiencies due to the addition of new engines can have an impact on the fuel efficiencies for the community and consequently impact the fuel costs for the relevant Zone.

The Board recognizes that in the normal course, any improved fuel efficiencies will make their way into the fuel forecasting system under the methodology that is currently in place in a short period of time, therefore, the Board sees no reason to deviate from the method of determining test year forecast fuel efficiencies.

However, for the community of Inuvik, there is a fundamental change in the configuration of engines, due to the conversion of gas engines to diesel and the base loading of diesel engines. NTPC acknowledged during hearing examination that the fuel efficiencies in Inuvik could improve significantly following the 2013/14 year:

> *So what I'm wondering is should the better fuel efficiencies resulting from the conversion as well as the installation of the new EMD engine be somehow captured in the forecast, at least for the 2013/14 year?*
>
> *A. Yeah, the conversion of the Wartsila from gas to diesel will be completed June next year. What I expect to happen, based on what I've seen in many similar projects, the first year of operation there will be teething problems with that and we will inevitably be running a combination of EMDs and the Wartsilas for anywhere between 6 months and a year. I don't expect it to go that smooth. So the first year of operation I would expect the fuel efficiency to be still roundabout 3.5.*
>
> *The Wartsilas are about -- after that I would expect the impact of the Wartsilas to come through and we'll see improved fuel efficiencies in the range between 5 and 8 percent depending on load factors.* [T303, L20 – T304, L14]

Schedule 3.3.2 indicates the diesel generation in the Thermal Zone is 76,014 Mwh in 2013/14 and the corresponding cost is $24.3 million. Schedule BR.NTPC-25a-4 indicates Inuvik generation constitutes approximately 44% of the total Thermal Zone diesel generation. The Board considers that a 5 to 8 percent improvement in the fuel efficiencies for Inuvik could potentially result in a material reduction in the diesel costs for the Thermal Zone.

Considering the materiality of the potential fuel cost reduction following the conversion of gas engines to diesel and the base loading of diesel generation, the Board considers, in this particular instance, the benefit of the fuel conversion should be reflected in customer rates without having to wait until the next GRA. Accordingly, NTPC is directed to address, at the time of the Compliance Filing Application, a method of recognizing the expected improvement in fuel efficiencies at Inuvik, in the rates for years commencing after the 2013/14 Test Year.

5.2 Inuvik Gas Supply

The TGC stated the following in Argument:

> *"Given the above, TGC submits that the Board should direct NTPC to prepare a comprehensive analysis of the issue surrounding the failure of gas supply in Inuvik, including the identification the basis for the failure, required reporting from the gas supplier and associated communications, and the analysis of any stranded costs (including prepaid gas not delivered), so that the situation is fully understood and similar events may be better avoided in the future."* [TGC Argument, P14, Para 51]

NTPC responded in its Reply:

> *"The Corporation notes that it did obtain its own reserve report confirming the reserve estimates of the gas supply. However, NTPC would not possibly be able to complete the requested broad analysis surrounding the failure of the Inuvik Gas Supply as the Corporation is not privy to most of the information contemplated in such an analysis. Inuvik Gas Ltd. ("IGL") is the distributor of natural gas in Inuvik and the company from which NTPC purchased gas for generating electricity. As the owner of the gas, IGL has the proprietary information regarding the issues surrounding the gas well failure, including the identification and basis for the failure and any reporting obligations. In NTPC's experience, disclosure of this information is not typically contemplated under sales agreements such as the one in place between NTPC and IGL (provided in response NTPC.TGC-12(a)). As NTPC previously advised, NTPC understands that the loss of gas was unexpected and unforeseen and NTPC cannot complete any kind of meaningful analysis that would prevent this situation from happening again.*

> *The Corporation is also puzzled by TGC's recommendation that it provide further analysis of any stranded costs including any "prepaid gas not delivered". As part of the Application the Corporation has fully disclosed all fuel costs related to its revenue requirement and confirmed there are no prepaid gas expenses that have not been delivered from IGL. Further, the Corporation filed a project permit application regarding the Inuvik plant conversion and provided further capital cost information supporting this project as part of the Application. TGC had ample opportunity to further test this issue within the regulatory schedule set out by the Board. It did not do so, but rather filed a letter stating "the TGC recommends the Board approve NTPC's application for the major project permit respecting the Inuvik Gas Engines Conversion to Diesel Project Application." As such, TGC's recommendation should be rejected."* [NTPC Reply, P8, L27 – P9,L16]

Board Findings:

The Board agrees with NTPC that it does not have the information required to fulfill the recommendation from TGC. Moreover, the Board agrees with the views of NTPC that these matters would have been more appropriately raised by the TGC in other regulatory proceedings on earlier applications filed by NTPC and Inuvik Gas Ltd.

6. NON-PRODUCTION FUEL, OPERATIONS AND MAINTENANCE EXPENSES

In its September 19, 2012 update, NTPC revised its 2012/13 and 2013/14 non-production fuel, operations and maintenance forecasts.

The 2012/13 forecast was decreased by $216,000 to $37,064,000. The $216,000 decrease consisted of a $180,000 decrease in salaries and wages and a $36,000 decrease in non-production fuel and lubricants.

The 2013/14 forecast was decreased by $37,000 to $38,597,000. The $37,000 decrease was in non-production fuel and lubricants.

Interveners raised concerns with NTPC's forecasts for salaries and wages and for supplies and services. Each topic is addressed in the following sections.

6.1 Salaries and Wages

In its September 19, 2012 update, NTPC revised its 2012/13 salaries and wages forecast to $22,244,000, a reduction of $180,000 from the application. The reduction was the result of the forecast of $360,000 for the apprenticeship program being cut in half due to the program not being initiated as quickly as anticipated and actual hiring in the year being delayed.

The forecast for 2013/14 of $23,492,000 was unchanged from the application.

In its Argument, YK/HR highlighted NTPC's response to BR-NTPC-4 by noting large fluctuations in the year-to-year level of spending on salaries and wages in the Snare Zone and in the Head Office and Regional Office. YK/HR indicates that NTPC did not provide a satisfactory response to explain the fluctuations and that this undermines the reliability of the information provided. The fluctuations lead YK/HR to question the accounting and management of costs. However, YK/HR did not make a recommendation to the Board on this matter.

YK/HR also raises the issue of an increasing ratio of fringe benefits in the Test Years (37.06% in 2011/12, 40.54% in 2012/13 and 41.74% in 2013/14). YK/HR states that the reasons provided by NTPC explain why salaries and wages would be increasing but do not explain why the ratio of fringe benefits are also increasing. YK/HR notes that NTPC has confirmed that it has not increased its benefits program so there is no reason for the ratio of benefits to be increasing. YK/HR recommends that the cost of employee benefits be limited to the forecast for 2011/12 of 37.06% of Total Regular Payroll for Distribution and Transmission. YK/HR states that this results in a reduction of $92,000 in 2012/13 and $136,000 in 2013/14.

In its Reply, NTPC responded to YK/HR comments on year-to-year salary fluctuations as follows:

> *"…The Corporation was specifically tested in this area during the course of the hearing. The Corporation explained, among other things, that salary allocations are not completed within rate zones during the intervening years in the same manner when calculating the Corporation's revenue requirement. This results in some "lumpiness" when comparing year over year results in salaries. However, the overall results are complete and reliable. As described at page 3-7 of the Corporation's Application, the average increase in salaries since 2007/08 is 3.4% per year, which reflects wage rate inflation over the intervening years. In addition, NTPC's employee compliment has been maintained at a level consistent with 2007/08 and was not challenged by YK/HR. As a result, the overall salary forecast is reasonable and should be approved."* [NTPC Reply, P9, L22-31]

On the matter of the ratio of fringe benefits, NTPC responded as follows:

> *"YK/HR's recommended reduction is arbitrary and once again unsubstantiated by any evidence. Fringe benefits as described at page 3-6 of the Corporation's Application are prescribed amounts that the Corporation must incur either by legislation or its collective agreement with the Union of Northern Workers. As per Revised Attachment YK/HR.NTPC-2 (c) the ratio of fringe when compared to regular payroll for all other areas except distribution and transmission is forecast at 39%. The same ratio for the distribution and transmission areas is estimated at 41% which reasonably represents the levels of fringe benefits that the Corporation will incur during the test years. As a result, YK/HR's recommended reduction in salaries and wages should be rejected."* [NTPC Reply, P10, L1-9]

In its Reply, YK/HR maintained its recommendation of a reduction to the ratio of fringe benefits.

Board Findings:

On the matter of the year-to-year fluctuations in salaries and wages, the Board shares the concern expressed by YK/HR. NTPC's explanation "*that salary allocations are not completed within rate zones during the intervening years in the same manner when calculating the Corporation's revenue requirement*" is a concern to the Board. NTPC is regulated on a rate zone basis. As such, the Board expects NTPC to be able to provide the Board and interveners with information at least down to a rate zone level.

It is the Board's view that NTPC should not be maintaining a different level of expense tracking in the intervening years as compared to the Test Years. For the forecasts in the Test Years to be considered accurate and reliable they need to be based upon accurate information from the non-test years. In the Board's view, confidence in the forecasts is somewhat undermined given NTPC's current practice. However the Board will not be issuing a direction on this matter within this Decision. The Board will address this matter further in its upcoming proceeding on minimum filing requirements.

On the matter of the ratio of fringe benefits, the Board agrees with YK/HR that NTPC has not provided a suitable explanation for the 3.48% (2012/13) and 1.20% (2013/14) increases in the fringe benefit ratio for distribution and transportation. The reasons provided by NTPC explain the increase in salaries and wages but do not explain the increasing ratio of fringe benefits.

The Board notes NTPC statement that YK/HR's recommendation on this matter is arbitrary and unsubstantiated by the evidence. The Board reminds NTPC that the onus is on it to provide the evidence to substantiate its requested revenue requirement. In this instance, it has not done so and on this basis, the recommendation from YK/HR cannot be anything but arbitrary given the lack of evidence filed by NTPC.

The Board directs NTPC that in its Compliance Filing Application, the ratio of fringe benefits for distribution and transmission is to be set at 37.06% for Test Years 2012/13 and 2013/14.

6.2 Supplies and Services

In its September 19, 2012 update, NTPC did not change its 2012/13 and 2013/14 supplies and services forecasts from the $11,812,000 and $12,049,000, respectively, that were in the original application.

In its Argument, NTPC highlighted that there are two major factors for the supplies and services expense increasing since the 2007/08 test year – 1) an increase of $0.214 million in insurance premiums due to higher gross plant and 2) an increase in communication charges of $0.279 million due to the remote diesel SCADA systems that have been developed. It is NTPC's position that the remaining increase largely reflects inflation since the 2007/08 test year.

When questioned at the hearing as to why the supplies and services forecast increases in 2013/14 after having had yearly decreases in 2010/11, 2011/12 and 2012/13, NTPC responded as follows:

> *Q. If we look at several years we see that the supplies and services expense decreases for -in each of the years 2010/11, 2011/12 and 2012/13, and then in 2013/14 you're showing an increase. So we thought we saw a trend there and wondered why that trend would not continue into the 2013/14 year, can you help with us that?*
>
> *A. Yes, for the purposes of calculating the 13/14 forecast we assume that inflation factor of 2 percent.*
>
> *A. MS. GOUCHER: If I could add to that, Mr. Marriott. The Corporation over the last several years leading up to this rate application, as I mentioned in my opening comments, has committed to trying to reduce costs in those areas where it has active management. So we have made considerable strides, particularly in the area of supplies and services, because that is one of those controllable costs.*
>
> *Having said that, we are a utility and the nature of our business has not changed materially from year to year. Although we have gone through a series of years where we've been able to reduce costs in this area. The second test year fiscal 2013 reflects the end of those adjustments and reflects instead an increase at inflation which, again, is – as I indicated, is a commitment of the management, the Board of directors and the shareholder on a go-forward basis. For those areas such as supplies and services where we are actively managing costs and they are more so in our control than perhaps some other areas, we have done what we can over the past several years to reduce costs in those areas and now what you're seeing on a go-forward basis is increases in line with inflation.* [T192, L25 – T194, L10]

In its Argument, YK/HR stated:

> *"…There has been a steady decline in costs since 2009/10. In 2010/11, Supplies and Services expense decreases by $711,000. In 2011/12, Supplies and Services expense are forecast to decrease by $697,000. During those two fiscal years Supplies and Services expense decrease by $1,408,000, yet NTPC only forecasts a reduction of $171,000 for 2012/13, and an increase of $236,000 in 2013/14. NTPC explains the 2012/13 reduction as due to stretch objectives and the increase in 2013/14 as due to inflation. Given the recent trend in declining Supplies and Services expenses, and the fact that NTPC imposes stretch targets, YK/HR submit that there is no need for an increase in 2013/14. As such, the forecast for Supplies and Services should be $11,812,000 for 2013/14, a reduction of $236,000."* [YK/HR Argument, P12, Para 47]

In its Reply, NTPC stated:

> *"As discussed, the intervening years had a number of one-time events and corrections that have skewed the year over year comparisons. As a result, the trend experienced during the intervening years cannot be expected to continue. In addition, the Corporation further explains the increase in supplies and services to be driven by two notable events; an increase in insurance premiums and communication charges. Absent these notable items, total supplies and services have increased 2.3% over the 2007/08 test year when rates where last set. YK/HR did not test or dispute these increases in insurance premiums or communication charges. Incorporating an inflation factor for 2013/14 supplies and service is reasonable as the Corporation is subject to inflationary pressures. As such YK/HR's proposal should be denied."* [NTPC Reply, P10, L15-24]

Board Findings:

The Board accepts the explanation provided by NTPC for its 2012/13 and 2013/14 supplies and services forecasts, namely; the large decreases in the preceding years were due to cost-reduction efforts; and the forecasts for the 2 Test Years in question represent the effect of inflation.

As such, the Board will not issue any direction to NTPC on this matter.

7. AMORTIZATION

An amortization study was completed by Gannett Fleming, for purposes of the GRA, to determine the amortization parameters and rates. NTPC indicates on the basis that the study is not proposed to be implemented for Test Year 2012/13, there is no impact of the study on the first Test Year. The impact of the amortization study on the 2013/14 amortization expense is as follows:

- Increased rates for changes in lives - $1.038 million (details provided in BR.NTPC-11(e) Table 3);
- Reduction arising from negative salvage pause approach – negative $2.098 million (as compared to what was previously in rates);
- True-up - $2.584 million (details provided at page A-52 to A-53 of the Application); and
- Total - $1.534 million increase.

As part of the amortization study, NTPC proposed changes to the life parameters for a number of asset accounts. BR.NTPC-33, Table 1 shows the impact of the proposed changes to life parameters (excluding proposed changes to salvage) alone, including true up differences, contribute to an increase in amortization expense of $2.2 million.

This increase is offset by NTPC's proposal to set all net salvage percentages equal to zero under a proposed pause approach for negative salvage.

7.1 Net Salvage and Implementation of Pause Approach

NTPC states due to a current accumulated amortization surplus in the net salvage accounts, it is proposing a “pause” in collection of new salvage amounts through rates until this balance is reduced.

NTPC states the reason for the pause approach is to permit the current $20 million surplus in the salvage accounts to be drawn down. NTPC states, once this is complete, it is anticipated that the $1.5 million annual accrual to the salvage reserve will need to be incorporated into rates (at a future GRA). NTPC states, given that the NTPC revenue requirement is in the order of $100 million, the impact of the end of the pause approach is anticipated to be a rate pressure of 1.5%.

The determination that there is a surplus in the salvage accounts is based on a split of the total accumulated amortization balance between accumulated amortization for original cost of assets and negative salvage, performed in 1994/95 for the 1995/98 GRA. NTPC acknowledges that despite having split the balances for original cost of assets and negative salvage, depreciation studies performed in 1994/1995 (for the 1995/98 GRA) and in 2000 (for the 2001/03 GRA) did not separately analyze the balances, but rather treated accumulated amortization as a combined value for each asset class. NTPC states, as the split was performed almost 20 years ago, NTPC does not have detailed information on the approach and rationale for particular mathematical approach taken to perform the splits. NTPC states, Gannett Fleming was not involved in preparing the splits at the time.

The total accumulated amortization balance (for original cost of assets and negative salvage) as of year-end 2010/11 is $146.04 million. NTPC's evidence indicates, accumulated amortization applicable to original cost of assets is $111.229 million while the accumulated amortization applicable to net salvage is $40.831 million. Other reconciling items make up the balance of minus $6.017. [BR.NTPC-16] As a result of the proposed allocation of total accumulated amortization there is a reserve deficiency applicable to the original cost of assets amounting to $37.8 million as shown in Schedule 2 (page A-53) and a reserve surplus applicable to net salvage of $20.223 million as shown in BR.NTPC-11, Table 2.

Board Findings:

The Board notes there are some uncertainties over the allocation of the accumulated amortization balance between accumulated amortization for original cost of assets and negative salvage. In this regard, the Board notes NTPC's acknowledgment the split of accumulated amortization (between accumulated amortization for original cost of assets and negative salvage) was performed almost 20 years ago and NTPC does not have detailed information on the approach and rationale for the particular mathematical approach taken to perform the splits. NTPC also states Gannett Fleming was not involved in preparing the splits at the time. The Board notes the proposed pause approach to the recovery of negative salvage is based on the assumption there is indeed a surplus in the accumulated amortization for negative salvage.

Notwithstanding the uncertainties associated with the split, the Board notes that the difference in true up for reserve differences is not materially different whether the split approach or the combined approach were adopted. More specifically, the true up for reserve differences amounts to $2.584 million based on the assumption the accumulated amortization were split between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage and if the pause approach for negative salvage is implemented. However, from Table 1 of BR.NTPC-34, the Board notes that if the accumulated amortization were not split (between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage) the true up amount would be $2.361 million. Therefore the splitting of the accumulated amortization contributes to an increase in the true up amount of $223,000.

Given the relatively small difference in the true up for reserve differences, the Board accepts the split between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage as proposed by NTPC for the purposes of these proceedings. Further, given the surplus in the accumulated amortization for net salvage, the Board also accepts the pause approach for negative salvage for the purposes of this Decision.

Noting the uncertainties over the split in the accumulated amortization balance discussed above, the Board directs NTPC to provide evidence to support the split between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage at the time of the next GRA.

7.2 Regulatory Treatment of Insurance Proceeds and Asset Retirement

NTPC indicates an amount of $13.1 million, shown as a reconciling item between the gross plant in service as per Schedule 5.1 and the amortization study in BR.NTPC-16, representing total insurance proceeds received by NTPC in the past, was credited against assets [BR.NTPC-38b)]. This includes items such as insurance recoveries on the Fort McPherson fire ($5.3 million) and the L199 splice failures ($1.6 million). NTPC states the accumulated amortization balance of $6.810 million, also shown as a reconciling item in BR.NTPC-16, is simply the sum of amortization against each of these balances up to March 31, 2011.

NTPC states when it receives insurance proceeds towards an asset, NTPC records that asset in its appropriate FERC account, and records the insurance proceeds as an offset to that asset, in the same FERC account. These insurance proceeds are then amortized at the same rate as the underlying asset. This same “offset” approach (crediting the insurance proceeds against the asset) is used in the financial statements and in the GRA. The net effect is much like a customer contribution. [BR.NTPC-38b)]

NTPC states for the purposes of the depreciation study, it is necessary to use the true gross book value in determining the appropriate life and depreciation rate for the assets in each FERC account. This is why insurance proceeds are added back to the Gross Plant and Accumulated Amortization balances in coming up with the plant to be studied in the amortization study. NTPC states once the appropriate rate for each FERC account is determined, this same rate is applied to the asset gross book value, to any insurance proceeds against the asset, and to any customer contributions against the asset.

Board Findings:

The Board notes, from BR.NTPC-16, Tables 1 and 2, that the insurance proceeds and accumulated amortization are not reflected in the specific FERC accounts that include the relevant assets, by virtue of the fact they are treated as reconciling items. From the proposed treatment of insurance proceeds, It appears to the Board that the assets that were the subject of the insurance claim are remaining in the relevant plant account at original cost although the physical assets, such as the Fort McPherson plant, may no longer be in service. The Board is concerned that unless the insurance claim amounts exactly match the original costs of the corresponding assets that were the subject of the insurance claim, the application of an amortization rate developed on the basis of an Iowa curve to a plant account that includes the original cost of assets that are no longer in service may result in the annual amortization expense being misstated.

This leads to a broader question concerning NTPC's practices regarding assets that are no longer in service. The Board has looked at Schedule 5.1 and neither the gross plant balance nor the accumulated amortization balance, reflect any asset retirements during the 2010/11 to 2013/14 period. Again, the Board is concerned the application of an amortization rate developed on the basis of an Iowa curve to a plant account that includes the original cost of assets that are no longer in service may result in the annual amortization expense being misstated.

NTPC is directed to address how its practices regarding treatment of insurance proceeds and retirement of assets that are no longer in service, from gross plant in service, results in the appropriate amortization expense and amortization of reserve differences for the Test Years. If the Board's comments give rise to any corrections to the gross plant used for calculation of amortization expense, NTPC is directed to provide the corrected amortization expense at the time of the Compliance Filing Application.

7.3 Individual Accounts

As indicated earlier in Section 7.0, NTPC proposed changes to life parameters which result in material increases in depreciation expense. The basis for changes in life parameters for some of the accounts were discussed through information requests and in Argument and Reply.

Account 341.00 – Diesel Plant - Structures and Improvements

NTPC proposed a change in the Average Service Life ("**ASL**") for account 341.00, reflecting a change in the Iowa Curve, from 40R2 to 30S2.5.

NTPC's Depreciation expert, Gannett Fleming, states the mortality experience as witnessed in the retirement rate study for this account provides the basis for the development of the average service life estimate. The Iowa 30-S2.5 as recommended provides a good fit to the historic retirement pattern through the period of statistical reliance, is within the range of approved average service lives for comparable peer utilities, and is consistent with the expectation of the operational and management staff of NTPC. [Ex 2; Appendix A, P A33]

With respect to NTPC's proposal for Account 341.00, TGC submitted a review of the peer electric utilities reveals the following:

- Northlands uses an ASL of 50 years with a 50-S1.5 curve
- Yukon Electrical Corp uses an ASL of 40 years; with a curve of 40-R2.5
- Qulliq Energy Corporation an ASL of 35 years; with a curve of 35-R2.5
- Manitoba Hydro uses an ASL of 30 years; with a curve of 30-R3

The TGC submitted, at a proposed ASL of 30 years, NTPC is at the bottom end of the average ASL for the above noted peer utilities. The TGC submits greater weight should be given to the experience of the peer group of utilities and accordingly, recommended NTPC should be directed to use an ASL of 39 years, reflecting the average experience of the peer group.[TGC Argument, P40, Para 140]

Account 343.00 – Diesel Plant – Prime Movers

NTPC proposed a change in the depreciation parameters for account 343.00 reflecting a change in the Iowa Curve, from 25S2.5 to 20R3.

Gannett Fleming states, the original life table as provided indicates significant retirement ratios beginning in the first 10 years of the account's life and continues through to approximately age 25. By age 30 the plant exposed to retirement is less than 1% of the total plant exposed to retirement over the account's life. Therefore the Iowa curve fitting focused on the original life table through to age 30. The Iowa curve matching procedures employed by Gannett Fleming resulted in an Iowa 20-R3 being considered the best fit to the historic retirement trends. Gannett Fleming states, the Iowa 20-R3 represents a shorter life estimate than the currently used Iowa 25-S2.5, and is shorter than the peer range of 25 to 27 year estimates. However, the site reviews and operational staff reviews did not indicate any reason to believe that the plant currently in service should have any significant longer life indications than has been experienced in the past. [Ex 2, Appendix A, P32]

With respect to the NTPC proposal respecting Account 343.00, TGC submitted, a review of the peer electric utilities reveals the following:

- Northlands uses an ASL of 25 years with a 25-R1.5 curve
- Yukon Electrical Corp uses an ASL of 27 years; with a curve of 27-R2.5
- Qulliq Energy Corporation an ASL of 25 years; with a curve of 25-R1.5108

In TGC's view the foregoing shows NTPC, at a proposed ASL of 20 years, is well below the bottom end of the average ASL range of 25-27 years for the above noted peer utilities, and 6 years below the Average ASL of 26 years. In TGC's view, greater weight should be given to the experience of the peer group of utilities. TGC submitted, given that 2 of the 3 peer group of companies have an ASL of 25 years, NTPC should be directed to use an ASL of 25 years, i.e. no change from the 25-S2.5 curve currently approved by the Board for Account 343.00. [TGC Argument, P41, Para 145]

In its Reply submission, NTPC stated the survivor curve estimates as recommended by Gannett Fleming for Accounts 341.00 and 343.00 considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined through conversations conducted as part of the study with operations and management personnel; incorporation of the knowledge that Gannett Fleming has gained through the completion of a number of NTPC assignments over a number of years; and survivor curve estimates from previous studies of this company and other electric generation, transmission and distribution companies. As such, the Gannett Fleming recommendations were based on significant review of a number of considerations, only one of which was the review of peer companies. To ignore all of the other factors, as is recommended by TGC, will result in a life estimate that is:

- Not consistent with 49 years of relevant retirement history;
- Not consistent with the views of the Corporations operations and management staff; and
- Not consistent with the operating practices and policies of the Corporation

The TGC submitted, in the event the Board is inclined to approve the revised deprecation rates as filed in this Application, the increases should be phased in over the 4-year period ending 2015/16 to coincide with NTPC rate design proposals. [TGC Argument, P41, Para 146]

In Reply, NTPC submitted:

> *During the transition years (2012/13, 2013/14 and 2014/15) the lowering of costs would solely serve to reduce the contribution from the GNWT (as customers would still face 7% increases). However, the entire value of this "savings" would have to be made up by depreciation expenses recorded in future regulatory accounts in years where GNWT contributions were not available, with the result that the ratepayers would pay higher rates in future than they would have paid.* [NTPC Reply, P12, L29-34]

Board Findings:

The Board notes the NTPC proposed reductions in ASL and life parameters for the following major accounts have a significant impact on the depreciation expense:

Ac #	Description	Original Cost March 31, 2011	Existing Life Parameter	Proposed Life Parameter	Peer Group Average ASL	Impact of Life Changes
341	Diesel Plant Structures and Improvements	$40,921,982	40-R2	30-S2.5	39 Years	$772,141
343	Prime Movers	$48,087,155	25-S2.5	20-R3	26 Years	$609,957
345	Accessory Electrical Equipment	$19,767,023	28-S2.5	21-L4	28 Years	$541,892
	Source: BR NTPC 33 Table 1 and BR 33a					

The factors considered by Gannett Fleming in arriving at the proposed ASL and life parameters are set out in BR.NTPC-33d). This response indicates 60% reliance was placed on the historical retirements for account 341 while, 80% reliance was placed on historical retirements for accounts 343 and 345, in order to come up with the recommended parameters.

The Board notes the proposed ASLs for each of the above accounts are significantly lower than the peer group average ASLs. Given this information, the Board is not persuaded such a significant reduction in ASLs should be approved in a single move based primarily on the analysis of historical data reviewed by Gannett Fleming, as part of these proceedings. The Board considers a move that is about 50% of the way towards the ASLs proposed by NTPC would provide an appropriate balance for the purposes of these proceedings. Accordingly, the Board directs NTPC to make a directional move in the Average Service Life parameter for the above noted accounts by reflecting ASLs of 35 years for account 341, 23 years for account 343 and 25 years for account 345, in its Compliance Filing Application.

7.4 Account 391.04 Office Furniture and Equipment – Gains and Losses

Schedule 2 of Appendix A shows a negative balance of $2.079 million in the accumulated amortization for account 391.04. NTPC states, the $2.079 million recorded in FERC 391.04 represents an accumulated amortization shortfall from past periods, largely due to retirements of computer hardware and software at a younger age than the "average" that was adopted for assets in FERC 391.

NTPC states, as part of first being regulated, it adopted the FERC system of accounts, which has a single account dedicated to "Office Furniture and Equipment", account 391. NTPC has used this account to capture all office furniture and all general purpose computer hardware and software. In the 1995/98 GRA this account was given a 13 year life, adjusted in the 2001/03 GRA to a 10 year amortization period.

NTPC states, over time, it has become clear that NTPC needed a more complete breakdown of the assets contained in account 391, as computer hardware and software did not exhibit life profiles that were at all similar to office furniture. In this GRA, NTPC states it has proposed to create 3 sub-FERC codes; one for computer hardware (5 years), one for office furniture (15 years), and a third for computer software (5 years). To accomplish this change, the assets in FERC 391 were individually separated into the 3 noted groups.

NTPC states the result of failing to have these sub-FERC accounts in the past is that computer retirements have driven a substantial accumulated amortization "loss on disposal" in the account, as computers regularly do not last 10 years. [BR.NTPC-38a)]

Board Findings:

Having regard to the reasons provided by NTPC, the Board accepts NTPC's request to amortize the accumulated loss in account 394.04 over 10 years.

8. STABILIZATION FUNDS

NTPC states that in accordance with the Board Decision 16-2010, as of December 2010, Diesel, Inuvik, Norman Wells, Taltson, Snare-Yellowknife fuel and Snare-Yellowknife water funds have been consolidated into one NTPC Territory-wide Consolidated Fuel and Water Rate Stabilization Fund ("**RSF**").

The operation of the RSF is described in BR.NTPC-10b) and in Section 3.6 of the Application. The purpose of the RSF is to flow through to customers, subject to a $2.5 million threshold, variances in fuel prices and purchased power prices relative to the GRA forecast, and to flow through fuel mix variances in dual fuel communities.

NTPC's proposal respecting the operation of the funds may be summarized as follows:

<u>Thermal and Norman Wells Zones:</u>

i. The actual cost of diesel (and where relevant purchase power cost per kWh) is compared to the forecast cost of fuel reflected in the base rate (i.e., the fuel cost as approved by the Board for the latest GRA test year).
ii. The difference is multiplied by the number of litres required to meet the load at the GRA approved efficiency factor (based on actual generation).
iii. The total fuel cost variance will be charged / credited to the RSF.
iv. For dual fuel communities, namely, Norman Wells, which uses purchased power and diesel generation and Inuvik, which uses diesel and gas generation, the cost impacts of changes in the mix of supply from the GRA forecast are flowed through to the RSF.

<u>Snare Zone:</u>

v. For the Snare Zone, the kWh variance based on the following will be charged / credited to the RSF based on the GRA approved efficiency and fuel price:

a) Where the hydro generation exceeds 220 GWh/year, a kWh savings from above-average water will be calculated.

b) Where the hydro generation is below 220 GWh/year, but diesel is still required on an actual basis, any costs for diesel generation kWh in excess of that included in rates (1.2 GWh/year) will be charged to the RSF.

<u>Taltson Zone:</u>

vi. For the Taltson zone, any diesel generation built into base rates will not be charged via the fund, but fuel for diesel generation which exceeds this level is charged to the fund.

With respect to the proposed inclusion of variances relative to the Taltson Zone in the RSF, NTPC states, it has long had an approved water stabilization mechanism for Taltson although this mechanism has been considered “inactive” due to the low level of loads on that system. However, with the initiation of a consistent principled Consolidated Stabilization Fund for all of NTPC’s customers across NWT, activation of this fund is now appropriate.

The TGC submitted, for communities where dual fuel sources are used, one as a primary source and the other as a backup, the costs of both should be shared across all of NWT, consistent with the GNWT Guideline 6, as approved in Decision 16-2010. [TGC Argument, P13, Para 43]

In its Reply submission, NTPC stated it is precisely NTPC's proposal that the Fuel and Water Stabilization Fund capture all variation from all fuel sources used for generation purposes. NTPC stated it has specifically sought approval to expand the RSF in three areas (Taltson hydro, Norman Wells fuel and Snare-Yellowknife base diesel) to achieve this precise objective.

The TGC also referred to Board Directive 7 from Decision 16-2010 requiring NTPC to work with Northland to develop a mechanism for territory wide sharing of the stabilization fund. TGC submitted NTPC should be directed to provide the results of its discussions with Northland at the earliest possible opportunity, and no later than the Compliance Filing in response to the Board Decision on this 2012-2014 GRA. Further, notwithstanding the passage of time, NTPC should address whether it can comply with the Directive to more broadly share the stabilization accounts across all NWT communities effective April 1, 2011 as anticipated by the Board in Decision 16-2010. [TGC Argument, P12, Para 37]

In its Reply submission, NTPC states the delay in fulfilling the Board Directive is largely due to other regulatory proceedings with both utilities. Imposing an aggressive deadline may not be practically achievable as the Corporation's resources will be fully engaged in completing the 2012/14 GRA compliance filing. Further, any directive would only bind NTPC. NTPC states, the Corporation fully intends to fulfill the requirements of this directive as soon as possible and intends to engage with Northland to advance this directive in the near future. However, NTPC submits a firm deadline is not practical or necessary in the circumstances. [NTPC Reply, P6, L33 - P7, L6]

Board Findings:

The Board has examined NTPC's proposed mechanics for operation of the RSF as applicable to the Thermal and Norman Wells Zones and accepts them as filed.

With respect to the Snare Zone, NTPC confirmed during the hearing, the cost of any diesel generation kWh in excess or less than that included in rates (1.2 GWh/year) will be charged or credited to the RSF. [T316, L24 – T317, L3]

NTPC also confirmed that the fund, as it applies to the Snare Zone, would operate to capture any variances in diesel costs relative to the GRA forecast and the operation of the fund is not intended to capture any efficiencies in terms of the optimization of water and diesel resources:

> *"What I'm wondering is, is there an incentive for the Corporation to optimize dispatch so that there is an optimum use of water and diesel resources?*
>
> *A. Well, there's absolutely an incentive for the Corporation to optimize the dispatch and to keep the diesels off. It's one of the driving factors in all of the considerations that go into the decisions that are made on the dispatch of this system. The Corporation has spent considerable effort and time and money to make sure that the hydro system can supply as much as possible beyond the next load. That's just a given.*
>
> *The question about the incentives built into the fund was an item of considerable debate in the last GRA and a number of re-filings. And at the end of the day what seemed like a possible theory of saying: We'll include this type of fuel and not that type of fuel was -- ended up being more complicated in trying to apply than the advantages it might have brought.*
>
> *And at the end of the day it was decided that the fund would operate to catch any variances in diesel rather than having to try to say: That kilowatt hour was due to peaking or that one was due to exercising or this extra bit of water I just used only arose because I peaked with my earlier kilowatt hour of diesel and I didn't use the water back then and so now it arose now and it saved me some diesel and do I get credit for that offsetting water, and all sorts of complexities that you start to get into when you try to label particular bits of generation."* [T320, P320, L16 – P321, L23]

In view of NTPC's proposal that the fund, as applicable to the Snare Zone, would capture all diesel cost variances, the Board considers the reference to the long-term average water forecast of 220 GWh per year, made by NTPC in its description of the fund operation, is redundant. Accordingly, the Board approves a revised wording for operation of the fund, as applicable to the Snare Zone, as follows:

> *For the Snare Zone, the fuel costs for diesel generation built into base rates will not be charged via the fund, but fuel costs for diesel generation which are greater or less than this level are charged or credited to the fund.*

The Board notes NTPC's view that the recovery of both volume and price variances relative to diesel costs through the fund is the only practical approach in the Snare Zone and that every effort is being made to maximize the use of the hydro resource by the corporation. Accordingly, the Board approves the recovery of both volume and price variances relative to the diesel cost forecast for the purposes of this Decision.

The Board continues to be concerned by an RSF mechanism which allows pass through of all diesel costs as this may not provide the appropriate incentive for NTPC to maximize use of the hydro resource. The Board directs NTPC to address the feasibility of NTPC assuming forecast risk on diesel volume variances for the Snare Zone at the time of the next GRA.

With respect to the operation of the RSF as applicable to the Taltson zone, the Board notes the following observations by the Board in Decision 16-2010:

> *"The Board considers the proposed exemption of NUL-NWT from the fuel and low water stabilization fund rider, due to the absence of a Taltson water stabilization fund at the present time, is appropriate. Accordingly, the Board approves the proposed sharing of fuel and water stabilization amounts for purposes of these proceedings.*

> *The Board notes that if a Taltson water stabilization component were to be required as part of the overall stabilization fund in the future, under the per utility sharing approach, NUL-NWT customers would share in NTPC's fuel and low water rider amounts but NTPC's customers would not share in the NUL-NWT fuel rider amounts. This might not be equitable to NUL-NWT customers.*
>
> *The per utility sharing of fuel and low water stabilization amounts could also result in significant differences in rider amounts for customers in NUL's service area and in NTPC's service area. Creating the potential for wide rate disparities between neighboring communities is not consistent with the principle of comparability of rates.*
>
> *Accordingly, the Board directs NTPC to work with NUL to develop a mechanism for Northwest Territories-wide sharing of fuel and low water costs, on a combined utility basis.* [Decision 16-2010, P19-20]

While NTPC has requested inclusion of diesel cost variances relative to the Taltson Zone in the RSF, the issue of sharing of fuel cost variances on a combined utility basis has not been accomplished as yet. The Board notes NTPC's statement that the Corporation fully intends to fulfill the requirements of the Board directive requiring operation of the RSF on a combined utility basis as soon as possible and that it intends to engage with Northland to advance this directive in the near future. In view of this, the Board denies the inclusion of the fuel cost variances relative to the Taltson Zone in the RSF until there is agreement between NTPC and Northland to operate the RSF on a combined utility basis. This means, if the RSF is triggered at any time prior to implementation of the RSF on a combined utility basis, the recoveries and/or refunds of the balance in the RSF would not apply to the Taltson Zone customers.

9. AFFILIATE CHARGES

9.1 Overhead Charges to Affiliates

In Decision 13-2007, Directive 42, the Board directed NTPC, in its next Phase 1 GRA, to file with the Board details of all transactions with the Corporation's parent, other affiliates and non-regulated operations, including details of how the transfer pricing is determined (fair market value, allocated costs), the allocation drivers used, as well as identification of all amounts included in the Revenue Requirement with respect to costs or revenues related to parent, other affiliate and non-regulated operations.

In response to BR.NTPC-24a), NTPC provided Table 1 showing the transactions between NTPC and its affiliates from 2007/08 to 2011/12.

Table 1:
Affiliate Actual Costs 2007/08 to 2010/11 and Forecasts 2011/12 to 2013/14 ($000s)

Transaction Description	2007/08	2008/09	2009/10	2010/11	2011/12[1]	2012/13	2013/14
NTPC Direct Costs	235	216	213	283	193	228	233
NTPC Utility Bills	17	17	12	8	7	9	9
Overhead Costs	150	150	150	116	87	74	75
Shared Services	60	62	98	144	106	161	164
Interest Expense	492	342	185	227	164	133	136
Dividends declared to non-regulated entities	800	850	800	825	500	400	400
Dividends paid to non-regulated entities	-	1,271	1,163	812	402	400	400

Note:
1. Actual transactions from April 2011 to December 2011 shown.

NTPC states, the majority of affiliate transactions require very little resources to manage throughout the year and therefore do not have material overhead costs directly assigned to them. The Corporation allocates overhead costs to recover time spent on affiliate matters that are not directly assigned such as purchasing and logistic matters, HR support, IT support and accounting assistance. All of which would include management time to supervise such activities. The costs for affiliate transactions are tracked with separate plant numbers and therefore are readily separated from regulated activities and not included in the Corporation's revenue requirement.

In order to fully comply with the foregoing direction, the TGC recommends that in all future general rate proceedings, NTPC should provide the full amount of costs incurred in running its utility operations (i.e. including costs incurred for affiliates) and provide separate line item(s) in the Revenue Requirement deducting costs incurred, either directly or indirectly, to support the operations of its affiliates. This would provide full and complete transparency of all costs incurred by NTPC, the regulated entity, and the nature and extent of costs charged or allocated to its affiliates. [TGC Argument, P35, Para 122]

With respect to interest on affiliate transactions, the TGC state NTPC has provided no evidence that the affiliates could actually avail themselves of a rate equal to prime less 50 basis points. On this basis, the TGC recommended that NTPC be directed to provide evidence at its next GRA to demonstrate the "prime less 50 bp" rate charged for loans to affiliates is in fact the same rate which NTPC incurs for such short term borrowings and to show both the costs of such debt as well as the offsetting recovery from the affiliates in the determination of its Revenue Requirement for the Test Year. [TGC Argument, P36, Para 126]

NTPC submits the process set out by the Board for the GRA Filing Manual is an appropriate means to address the recommendations made by TGC at paragraph 122, namely the presentation of costs ultimately charged to affiliates as opposed to regulated ratepayers. [NTPC Reply, P 35, L17-19]

Board Findings:

The Board agrees with the TGC that the information provided with respect to affiliates should provide the means for the Board and other parties to understand the accounting entries with respect to amounts recoverable from, or payable to affiliates, both on a forecast basis and on an actual basis. For example, with respect to shared services, response to TGC.NTPC-45(n)(vi) indicates costs for shared services include building leases, telecommunication costs and computer software costs. It is not clear in which regulatory account the costs/recoveries related to the shared services are reflected. Similarly it is not clear in which accounts interest payments/recoveries or overhead recoveries are reflected, both on a forecast and actual basis. Therefore, the Board directs NTPC to provide, at the time of the Compliance Filing Application, details explaining the accounting entries involved in recording each of the affiliate costs/revenues (other than dividends), for GRA forecast purposes and for recording actual results for financial statement purposes.

In response to Board Decision 13-2007, Directive 42, NTPC also did not explain the basis on which overheads, shared services and interest expense are priced. It is not clear whether the pricing method used is consistent with the affiliate transfer pricing policies as approved in Decision 6-2009:

> *Under the Cost Recovery Basis, the fully burdened cost of employees providing the shared service for the time period they are used by the Affiliate, including salary, benefits, vacation, materials, disbursements and all applicable overheads shall be used for determining shared employee costs. Where there are sharedcosts arising from the sharing of assets, an allocated share of capital and operating costs appropriate for the time period utilized by the Affiliate shall be used for determining shared asset costs.*
>
> *When a utility provides to or takes from an Affiliate services, resources or products, that do not fit the description of Shared Services outlined above the Board considers these to be For Profit Affiliate Services. The Board considers the transfer price respecting For Profit Affiliate Services should reflect the fair market value. The onus is on the utility to demonstrate the transfer price of the services, resources or products reflects the fair market value.* [Decision 6-2009, P20-21]

NTPC is directed to identify the transfer pricing policy and how it was used for pricing shared services including overheads and, interest expense/recoveries, at the time of the Compliance Filing Application.

10. SALES AND REVENUE FORECAST

NTPC indicates the forecast of customers for the Test Years were developed using the following approach.

For residential customers, 2011/12 customer count forecasts were forecast based on the 2010/11 average actual customer counts from December to March multiplied by the average annual population growth rate. 2012/13 and 2013/14 customer count forecasts were then estimated using the 2011/12 forecast customer counts multiplied by the population growth rates

For general service customers, the same method was used as described for residential customer counts with the exception that only 50% of the population growth rates were used. NTPC states a 50% factor was used because:

- General Service customer numbers tend not to change as frequently as residential customer numbers;
- There tend to be more residential customers in a community than general service customers.
- More of the growth in customer counts in the General Service customer class can be addressed from specific information

NTPC states, after a baseline customer count is developed, the Corporation checked, and where necessary adjusted the customer count to address new developments planned to have in-service dates in the forecast years for communities where the population growth percentage did not reflect similar patterns.

With respect to development of the usage forecasts, NTPC indicated the following approach was used:

> *"Monthly usage per customer (UPC) in actual years is calculated as actual sales for the month divided by the actual average annual customer number for each community. The forecast sales for each forecast year 2011/12, 2012/13 and 2013/14 are then calculated by averaging the last five years of monthly UPC and then multiplying by the forecast annual customer count. NTPC states, in 2013/14 additional UPC is added to Inuvik's general service and residential classes to account for a 5% increase in power demand as a result of the gas conversion, which subsequently raises UPC for the Thermal zone and Corporate wide, as a percentage of sales, compared to totals."* [BR.NTPC-2]

NTPC states, the usage per customer ("**UPC**") method is not used for lighting, wholesale or industrial forecasts. Instead the following methods were used:

> ***"Lighting:*** *The load forecast for lighting uses 2010/11 actuals for each forecast year and makes adjustments, where applicable, when lighting will be changed to more efficient lamps.*
>
> ***Wholesale:*** *Snare zone wholesale forecasts assume a 0.7% increase over the preceding year, which is equivalent to the 2011/12 forecast growth rate over 2010/11 actual wholesale sales. The Taltson zone wholesale forecast assumes a 5-year average, per month, using five of the last seven years as a rolling average.*
>
> ***Industrial:*** *Considering that no new mining activities are expected during the 2012/13 and 2013/14 test years, forecast industrial sales for the test years was assumed to remain at the forecast 2011/12 level."* [Ex 2; P2-14]

YK/HR submitted, despite NTPC's assertion that it has complied with Board Directive 7, NTPC has not used normalized heating or cooling degree days. Instead, NTPC has used a simple average with no trending. Further the 2012/13 forecast includes the 2011/12 average in the five year average, and the 2013/14 forecast includes the 2011/12 and 2012/13 averages. This approach results in a disproportionate weighting being placed on recent years. [YK/HR Argument, P8, Para 31 – P9, Para 33]

YK/HR recommended that the forecast UPC should reflect the recent patterns. That is that Snare zone residential UPC should reflect the pattern of increases as noted by YK/HR in Argument, and the Taltson zone residential and general service UPC should not decrease but remain constant at the 2011/12 average. YK/HR requested that the Board direct NTPC to provide evidence that its use of a five year average of UPC is a reasonable forecasting methodology and that the Board direct NTPC to investigate alternate forecasting methodologies and provide the results of the investigation at the next GRA. [YK/HR Argument, P10, Para 38 – P11, Para 39]

In its Reply submission, NTPC states the average UPC calculated over a five year period incorporates the effects of medium-term weather fluctuations, and thus represents a reasonable and practical approach to determining a temperature-normalized average UPC. Mr Bowman referred to some of the difficulties of developing weather normalized data:

> *"In NTPC's case, the loads are very diverse and distributed and very small. And loads can swing, particularly in the small communities, for many different reasons.* [T164. L7-10]
>
> *…*
>
> *In the case of NTPC, that is a very difficult thing to try to do because a lot of the weather data needed to do that is not available. And especially for the small communities. And also for small utilities the data that generates that line is often not very good at generating lines because it looks more like a scatter plot because there's a heck of a lot more going on in any small community than just the weather that's driving the changes in load. So you may have a cold winter but you may have had one house vacant and as a result -- or one -- your use per customer would be swung because that house is using much less power. And so you can see a lot of noise in there.*
>
> *I have been involved in hearings in places like Yukon where the utility there, Yukon Electrical has tried to do this weather normalization process, worked through a large stack of data and produced a substantial section of their rate application, and at the end of the day the R-squared or the statistical term that tells you how well you are aligned -- a single line summarizes your data is very low, it's very poor match to weather."* [T165, L6 – T166, L4]

With regard to the use of rolling averages including use of a given year forecast to develop subsequent year forecasts, NTPC submitted the same effect exists for the fuel forecasting approach that was specifically directed by the Board, and presumably reflects a willingness or desire to more heavily weight the more recent years. In NTPC's view this is not an unreasonable approach to forecasting. NTPC also states the evidence in this proceeding does not support YK/HR's claim (a) that in the last GRA 2007/08 test year NTPC's methods under forecast the average UPC in the hydro zones, and (b) that the current GRA is forecasting reductions in average UPC that are not justified based on the data. [NTPC Reply, P3, L36 – P4, L12]

Board Findings:

The Board has examined NTPC's customer forecasts for the Test Years, as well as the methods used to develop such forecasts and accepts them as reasonable.

The Board notes YK/HR's observations respecting lack of temperature normalization and the heavier weighting placed by NTPC on more recent year UPC numbers in developing its forecasts of UPC. The Board recognizes the difficulties of obtaining temperature normalization data for certain communities. However, noting YK/HR's request that NTPC investigate alternate forecasting methodologies and provide the results of the investigation at the next GRA, the Board directs NTPC to examine the following refinements with respect to its UPS forecast methodology for the purposes of the next GRA:

- For those communities where temperature normalization data is available, NTPC is to carry out regression analyses for all temperature sensitive sales, using degree days, trend variable(s) and any other relevant variables to develop a reasonable estimate of forecast UPC.

- For those communities where temperature normalization data is not available, NTPC is to use a straight 5 year average UPC over the most recent recorded (actual) years and use the actual growth rate over the same recorded years to project growth for the forecast years.

In the absence of any evidence to indicate, NTPC's forecast sales for the Test Years are not reasonable, the Board accepts NTPC's forecast sales as filed for the purposes of this Decision.

11. RATES

11.1 Rates Phase In Proposal

NTPC states the rate changes in this GRA are designed to achieve a level of rates that recover the full 2013/14 Revenue Requirement by the end of a four year transition period (“Full Rates”). NTPC states, during the transition period (2012/13, 2013/14 and 2014/15), rates will fail to achieve the full Revenue Requirement. Accordingly, NTPC and the GNWT have implemented funding measures to ensure the Corporation is able to continue to provide safe and reliable service and maintain financial viability during the transition period. As a result, GNWT funding in the amounts of $13.63 million in 2012/13, $11.484 million in 2013/14 and $4.892 million in 2014/15 will be provided to NTPC based on forecasts reflected in its Application. [T331, L18-20]

On September 19, 2012, NTPC filed an update to its Application. [Ex 13] The following Table shows the rate increases and shortfalls for the Test Years and for the transition period:

	2012/13	2013/14	2014/15	2015/16
	$000	$000	$000	$000
Total Revenue Requirement	102,225	107,304		
Revenue at Existing Rates	82,132	83,123		
Other Revenue	1,029	1,058		
Total Revenue	83,161	84,181		
Shortfall	19,065	23,124		
Revenue at Proposed Rates	87,672	94,763	101,144	106,246
Other Revenue	1,029	1,058	1,058	1,058
Total Proposed Revenue	88,700	95,821	102,202	107,304
Shortfall	13,525	11,483	5,102	0
Percent Increase in Customer Rates Year Over Year	6.745%	6.636%	6.733%	5.044%

NTPC requested approval of rates covering the rate transition period (including the 2 Test Years plus 2014/15 and 2015/16) as needed to achieve the full calculated level of rates.

In its IRA, NTPC stated that that a lower Board-approved 2012/13 revenue requirement would simply reduce the amount of the GNWT financial support for 2012/13. [Interim Rate Application, P2]

NTPC proposed increases to all energy rates, other than Norman Wells, totaling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells, NTPC proposed increases to energy rates of 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. NTPC proposed no changes to fixed monthly or demand charges.

For the purposes of 2012/13 interim rates, Norman Wells customers saw a 7% energy rate increase as did other customers. NTPC indicated it consulted with the Norman Wells community and the GNWT about phasing in rate increases for that community. Following this, NTPC requested that the final rates for Norman Wells reflect an additional increase of 8% for 2012/13 and 15% in each subsequent year, as needed to transition Norman Wells into the Thermal Zone. NTPC indicated it is not requesting recovery of the shortfall relative to Norman Wells arising from the implementation of a 7% interim increase for 2012/13 instead of the 15% now being requested for that year.

TGC expressed concern about the proposed increases in rates for Norman Wells.

TGC notes, once the final rates take effect, customers in Norman Wells are proposed to receive an additional 8% increase for the balance of 2012/13, followed by a 15% increase in 2013/14 and another 15% increase in 2014/15. TGC states, the impact of the stacking of significant rate increases in Norman Wells over the next 4 years will lead to rate shock; an annual 15% increase over the next 4 year is an increase in rates of 75%. This is not in the best interests of customers. In TGC's view, any such rate increase to comply with the GNWT's Guidelines should be phased-in over an appropriate length of time. TGC recommended NTPC be directed to provide a proposal which would implement a rate increase of no more than 7% per year for Norman Wells until full cost recovery is attained. [TGC Argument, P14, Para 47 - P15, Para 49]

In its Reply submission, NTPC states keeping Norman Wells' rate increases to 7% as suggested would simply defer and create a larger rate impact for customers beyond 2015/16, a rate impact that will need to be dealt with in transitioning Norman Wells to the Thermal Zone. In addition, and with exception to 2012/13, if Norman Wells' rate increases were limited to 7% for the next 4 years, additional revenue shortfalls will be created for every year that Norman Wells is not at full cost recovery. Once again, these shortfalls would have to be collected from customers by implementing additional shortfall riders in addition to any transitional rate increase to bring Norman Wells into the Thermal Zone.

NTPC submits its proposal to increase Norman Wells' rates 15% in each year as needed to achieve transition into the thermal zone as well as to achieve the full rates by 2015/16 is not rate shock. The Board has a long standing guideline that has allowed 15% as the maximum rate impact for customers. [NTPC Reply, P13, L23-26]

YK/HR submitted that any difference between NTPC's applied-for 2013/2014 revenue requirement and what is ultimately approved by the Board should be reflected in the rates for 2015/2016. For example, a decrease to NTPC's 2013/2014 revenue requirement should be reflected in a rate increase of less than 5% for most customers in 2015/2016.

YK/HR submitted, since NTPC is seeking approval of, *inter alia,* final rates for the 2012/2013, 2013/2014, 2014/2015 and 2015/2016 years, if the Board approves NTPC's Application, that it explicitly state that rates for all years shall be considered final. YK/HR submits in granting NTPC the relief requested, the Board should ensure that rates for the entire "transition period" are certain and not subject to further increases in addition to those approved in this Application. YK/HR submits, if NTPC's rates for the four years are approved as final, NTPC shall not be entitled to come back and ask for any further rate increases during the test period, nor should NTPC be entitled to collect any shortfall from the 2014/2015 and 2015/2016 years in future rates [YK/HR Argument, P13, Para 51 – P14, Para 52]

In its Reply submission, NTPC states it would appear that YK/HR is effectively requesting that the Board fetter its own discretion to carry out its statutory mandate in the future with respect to years that are presently not test-years. NTPC states, Sections 49 through 51 of *the Act* outline the powers and obligations of the Board, including the requirement to fix just and reasonable rates to be charged by NTPC with reference to the “fiscal year of the public utility in which a proceeding is initiated for fixing rates.” Although NTPC does not at this time anticipate requiring further rate adjustments for the years 2014/15 and/or 2015/16, a Board direction to this effect would fetter its discretion and prevent the Board from fulfilling its statutory duties outlined in *the Act* in the event NTPC was to bring a new GRA before it. [NTPC Reply, P15, L3-11]

Board Findings:

The Board approves in principle a phasing in of rate increases over a period of 4 years from 2012/13 to 2015/16, in view of the significant increases in Test Year revenue requirements over existing rates and in view of the arrangements made by NTPC for funding by the GNWT, in order to smooth out rate impacts to customers during the rates phase in period.

The Board notes NTPC's proposal that a lower Board-approved 2012/13 revenue requirement would simply reduce the amount of the GNWT financial support for 2012/13. The Board notes NTPC's confirmation that the GNWT maximum contributions to fund the shortfall amounts would be $13.63 million in 2012/13, $11.484 million in 2013/14 and $4.892 million in 2014/15, as set out in TGC.NTPC-9. [T331, L12-22]

Given that the maximum contributions from the GNWT for 2012/13 and 2013/14 have been negotiated, the Board directs that the GNWT contributions for 2012/13 and 2013/14 be recognized in the determination of rates for those years in NTPC's Compliance Filing Application.

With respect to the rates phase in for the 2014/15 and 2015/16 years, the Board notes NTPC's statement that the shortfall in 2014/15 at $5.102 million exceeds the available funding from the GNWT in the amount of $4.892 million for that year and, that upon final approval of the 2013/14 revenue requirement, if the shortfall still exists, the Corporation will consider alternative approaches for addressing the shortfall and setting of final rates. [Ex 13] NTPC is directed to address the 2014/15 phase in rate increase after giving effect to the Board's determinations in this Decision, at the time of the Compliance Filing.

The Board considers the establishment of phased in rates for 2015/16 requires an approved cost of service study by rate zone to ensure rates for each zone reflect the corresponding Zone based allocated costs. The Board will deal with this matter in Section 11.2.

The Board agrees with NTPC's view that acceptance of YK/HR's recommendation that rates for the 2014/15 and 2015/16 years be considered final, would fetter the Board's discretion to establish just and reasonable rates for those years. Accordingly, the Board rejects YK/HR's recommendation that the rates for all years during the phase in period be established on a final basis.

With respect to the transitioning of the community of Norman Wells into the Thermal Zone, the Board, in the interest of rate stability, considers it appropriate to phase in rate increases for Norman Wells with annual increases of 7%, as may be required and, applicable to energy rates, until Norman Wells rates are fully transitioned to reflect the corresponding rates as the rest of the rates within the Thermal Zone. In order to achieve this, Norman Wells base rates should be adjusted to equal the corresponding Thermal Zone base rates. The 7% increase per year for Norman Wells should be given effect to by way of a credit rider applicable only to Norman Wells customers. The annual shortfall in revenue due to the Norman Wells credit rider will be collected by NTPC from the Thermal Zone in its entirety, including Norman Wells, by application of a recovery rider to all of the Thermal Zone base rates. The Board directs NTPC to propose rates and riders for Norman Wells and the Thermal Zone in accordance with this finding in its Compliance Filing Application.

11.2 Cost Allocations by Rate Zone

NTPC states, in 2012/13 and 2013/14, customers as a whole are not fully covering NTPC's Revenue Requirement, and no zone is paying outside of the routinely recognized zone of reasonableness of 95%-105% for at least the next 3 years. In Tables 4.4 and 4.5 of the Application, NTPC indicates it is targeting revenue to cost ratios of 104.1% for the Hydro areas, which includes both the Snare and the Taltson Zone, and 96.7% for the Thermal Zone in 2015/16, which is the last year of the rate transition period.

In BR.NTPC-22, the Corporation provided a calculation of the revenue requirements by rate zone for 2011/12 and 2012/13. The allocated costs by rate zone are as follows:

Proportion of Costs by Rate Zone				
Zone	2012/13		2013/14	
	$000	%	$000	%
Hydro	35584	34.7%	37754	35.1%
Taltson	9973	9.7%	10714	10.0%
Thermal	56949	55.6%	59076	54.9%
Total	102506	100.0%	107544	100.0%

YK/HR raised issues respecting NTPC's proposed allocation of common costs by rate zone. Specifically, YK/HR submitted capital additions such as Line Tools, Hot Sticks, Truck equipment, and major tool purchases, Type 6 work as well as certain vehicle and machinery purchases are budgeted at corporate; yet the actual costs are eventually recorded in the communities that are served.

For example, with respect to Type 6 work, the majority of the work is in the thermal communities. However, using the last three years, which appears to be representative of the current spending patterns, YK/HR submits 93% of the Non recoverable Type 6 work, is attributable to thermal communities. With respect to vehicles and machinery purchases, YK/HR submits the cost of a pole trailer and off-road track digger included in vehicle and machinery purchases (estimated by YK/HR at $350,000 to $400,000) are designated for Inuvik; however these items are included under corporate. [YK/HR Argument, P6, Para 20-21]

YK/HR submitted, based on this sampling of costs that are misallocated, that it is concerned that the forecast methodology does not accurately reflect the tracking of actual results. For future rate applications, YK/HR recommends that the Board direct NTPC to implement a forecasting methodology that more accurately reflects how actual expenditures are recorded. This would include demonstration that the costs are allocated to the correct zone. [YK/HR Argument, P6, Para 22]

In its Reply submission, NTPC agreed in principle with YK/HR’s submission and indicated it has endeavoured to provide proper allocations to zones where the costs can be so categorized during GRA preparation. However, NTPC submits this is not always possible given the dynamic nature of a capital plan, and the tendency of certain “blanket” budgets to be Corporate-wide prior to the actual money being spent. [NTPC Reply, P15, L28-31]

NTPC further noted that past spending does not adequately predict which zones the future additions will occur in. This can be seen in undertaking which provides Actual Non-Recoverable Type 6 Work by Zone for actual years 2007/08 to 2010/11. On a per zone basis, the majority of actual costs do incur in the Thermal Zone, but in any given year (such as 2007/08 where the majority of costs were in the Snare Zone) it is hard to predict where costs will be incurred.

NTPC submits in the instance where a forecast cost within one of these cost groupings can be allocated on a community or zone basis, such as the case with the Off-Road Track Digger to be purchased for Inuvik, there could be a step in the forecast process that first directly assigns known costs that would otherwise be allocated to head office. [NTPC Reply, P16, L12-21]

In its Reply submission TGC submitted the evidence supports including the costs of D Group - Vehicle and Machinery Purchases as Corporate or Head Office. While YK/HR may suggest there is precision as to location of the pole trailer and the off-road, tracked digger, the evidence at the hearing clearly suggests NTPC cannot be "precise about where it's going to be spent", [TGC Reply, P10, Para 29]

Board Findings:

NTPC was directed in Decision 16-2010, Directive 14, to target 100% revenue to cost ratios for each zone and for each rate class within each zone unless there is some other restriction or over-riding rate design principle that would compel moving away from 100%. The Board recognizes this cannot be achieved at the zone level during the rates phase in period from 2012/13 to 2014/15. However, the Board notes NTPC is targeting to achieve certain revenue to cost ratio targets within the revenue to cost tolerance range of 95% to 105%, by 2015/16.

The Board notes the information provided by NTPC on the target revenue to cost ratios for the hydro areas combines both the Taltson Zone and the Snare Zone. On the other hand, Directive 14 from Decision 16-2010 required the target revenue to cost ratio of 100% to be applied to each of the rate zones. This means Snare and Taltson Zones are to be considered separately. Further, consistent with Directive 14, the Board considers NTPC should target a 100% revenue to cost ratio for each of the rate zones subject to other rate design criteria by 2015/16 when the rates phase in would be completed.

In order to continue the rate phase in by rate zone, the Board considers it necessary for NTPC to conduct a fully allocated zone-based cost of service study and design the phase in rate changes for 2015/16 having regard to this study. Accordingly, NTPC is directed to file a zone-based, fully allocated cost of service study based on the 2013/14 approved revenue requirement together with proposed rates targeting 100% revenue to cost ratios by rate zone in 2015/16, subject to other rate design criteria. The Board will refer to this as the 2015/16 Phase 2 Application. This Phase 2 Application is to be filed by September 30, 2014 which would allow at least 6 months processing time prior to the commencement of the 2015/16 fiscal year.

The Board notes NTPC's cost allocation study by rate zone provided in BR.NTPC-22. For the purposes of the 2012/13 and 2013/14 Test Years, NTPC is directed to file, at the time of the Compliance Filing Application, an update to the cost allocations shown in BR.NTPC-22 for 2012/13 and 2013/14, in Excel format, reflecting the Board's determinations in this Decision and showing:

- How rate base, return, amortization expense and other components of revenue requirement were assigned or allocated by rate zone;

- The proposed allocation of revenues from GNWT support by rate zone;
- The proposed revenues to be recovered through customer rates, by rate zone;
- How the proposed revenues by rate class would dovetail into the 2014/15 and 2015/16 rates phase in increases, by rate zone.

For the purposes of this update to BR.NTPC-22, the Taltson Zone should be considered separate from the Snare Zone.

NTPC is also directed to file proposed rates designed to recover the proposed 2012/13 and 2013/14 revenues from customer rates reflecting the update to BR.NTPC-22 referred to above.

The Board notes YK/HR concern that capital additions such as Line Tools, Hot Sticks, Truck equipment, and major tool purchases, Type 6 work as well as certain vehicle and machinery purchases are budgeted at corporate; yet the actual costs are eventually recorded in the communities that are served. The Board agrees the type of costs referred to by YK/HR are not common costs but rather, zone specific costs and should be assigned to each zone on a forecast basis using reasonable assumptions. NTPC is directed to reflect this direction in future GRA filings.

The Board also notes NTPC's acknowledgement that an Off-Road Track Digger is assignable to Inuvik. Accordingly, NTPC is directed to assign the cost of the off-Road digger to the Thermal Zone in the update to the cost allocations as set out in BR.NTPC-22, to be filed as part of the Compliance Filing Application.

11.3 Requirement for Phase 2

NTPC indicates the GRA filing achieves the objectives targeted in this GRA in a single package, with no need for a segregated "Phase 1" and "Phase 2" process. Specifically, NTPC submits the GRA achieves the following outcomes without a separate Phase 2 filing:

- *Adopts a simplified rate design that shares cost increases across-the-board: This approach is consistent with the principles of the GNWT funding and is consistent with recent practice in many Canadian jurisdictions. This approach also does not get distracted with excessive analysis on specific components of the rates (such as tweaking demand charges) but focuses on the energy component, which is the component best understood by customers and provides the best signals for conservation.*
- *This GRA focuses mainly on rate transition and a simplified rate design to the benefit of customers. No customer class or zone is paying their full cost of service, which would otherwise justify a Phase II study, during the transition years through to 2015/16 fiscal year. Further, it is important to note that customers also benefit from the avoidance of the costs associated with a Phase 2 process.*
- *Rates proposed are well below costs in the Test Years: Due to the magnitude of the GNWT funding available, all zones will be paying well below the pure costs to serve them in the Test Years 2012/13 and 2013/14.*
- *Rates proposed are at or below costs over the full 4 years of transition: Over the full 4 year transition, even with the proposed sequential rate increases each year, each zone will be at or below the costs to serve them.*
- *No need for second hearing to complete GRA: The rate proposals contained in the GRA, along with detailed zonal cost allocation, provide all necessary information for the Board to conclude that the rate proposals meet the requirements of the Act (i.e., that rates are just and reasonable).* [NTPC Argument, P8, L24 - P9, L7]

During hearing examination, NTPC was asked to comment on its intent in relation to doing a Phase 2 where it may look at the rate components in relation to the cost. In response NTPC indicated since there are number of rate transition issues being dealt with in these proceedings and no community or rate class is paying its full cost at the moment, a full Phase 2 is not being contemplated until 2015/16 or beyond that date:

> *"What's been included in the responses in this filing is that there are a lot of issues to deal with today and a lot of transitions that need to occur. And no class, no community is paying their full cost at the moment. It's the government funding that's making up the*

> *difference. So it's at least a number of years down the road before one would get to the point of needing to look at how precise we need to get, how close we're getting to the end goal. Probably 15/16 or beyond."* [T342, L13-22]

NTPC also noted it has yet to address the question whether there should be separate rate classes for Government and Non-Government customers when a cost of service study is performed:

> *"I'm also not sure when we eventually get to the point, which in the Corporation's proposal is a number of years down the road -- that we run a next detailed Cost of Service study, whether we would actually run separate classes -- for example, general service government versus general service non-government, or whether it would just be run as a general service class, but then the rates would be different between government and non-government. It's just not a question we wrestled with."* [T340, L21 – T341, L5]

Board Findings:

In Decision 16-2010, Directive 14, NTPC was directed to target 100% revenue to cost ratios for each zone and for each rate class within each zone unless there is some other restriction or over-riding rate design principle that would compel moving away from 100%.

In the preceding Section, the Board directed NTPC to file a 2015/16 Phase 2 Application in order to establish appropriate revenue to cost ratios by rate Zone. Consistent with Directive 14, the Board considers it appropriate to also target revenue to cost ratios of 100% by rate class, subject to other rate design criteria. Accordingly, NTPC is directed to file a cost of service study based on the 2013/14 approved revenue requirement, showing the allocation of costs by rate class and the design of proposed rates by rate class, for 2015/16, by September 30, 2014.

11.4 Government Customer Class

The GNWT's revised electricity policy guidelines dated February 11, 2011 require the Government rates move towards flat rates across each of the electricity rate zones, at the time of the next GRA. Pursuant to this requirement, NTPC was questioned as to when NTPC is targeting for Government rates to reflect the same rates by rate zone. [BR.NTPC-22h)]

NTPC indicates it has not developed any specific transition plan within this Application for government rates to be moved to a levelized structure, given that the customers within this class almost entirely represent either direct or indirect purchases by the GNWT. Instead, the Corporation focused on dealing with other material rate pressures that required GNWT involvement, notably the transition funding committed by the GNWT. NTPC also notes that the GNWT, as the customer for these Government rate classes, has not indicated a desire for rate restructuring at this time. [NTPC Argument, P31, L2-8]

Board Findings:

The Board is not persuaded by NTPC's reasons for delaying the implementation of flat rates by zone for Government rate customer classes. The Board considers implementation of the revised electricity policy guidelines respecting flat rates, by zone, for Government customers, is not likely to impact NTPC's overall rate proposals or the rates for non-Government customers. Accordingly, NTPC is directed to propose, in the Compliance Filing Application, a flat Government rate by rate class and by zone that recovers the same revenue for the Government class as the proposed community based Government rates, for each zone. The Board considers this will accomplish the goal of simplified rates and a flat Government rate by class in each zone.

12. TERMS AND CONDITIONS OF SERVICE

NTPC's Application requested a number of revisions to the Corporation's Terms and Conditions of Service ("**T&Cs**"). NTPC indicated in its Application that the revisions were intended to provide greater clarity and consistency as well as make the document easier to understand for customers, as well as NTPC personnel.

The Board notes that the majority of the revisions are of the 'housekeeping' nature and do not fundamentally alter the nature or scope of the section. These changes are approved. The Board's conclusion on the substantive amendment pertaining to the treatment of unclaimed security deposits is considered below.

Unclaimed Security Deposits

NTPC's proposed section 5.11 provides that in those cases where the Corporation is unable to locate a former customer to whom a security deposit is payable; and the deposit remains unclaimed for six years from the date the customer was disconnected, the deposit becomes the property of the Corporation immediately after the six year period has expired.

Board Findings:

NTPC clarified that clause 5.11 would only apply to customers who no longer have an active account with the Corporation, who no longer owe money to the Corporation and are entitled to the return of a security deposit but cannot be located for any number of reasons. Under cross examination, NTPC confirmed that the situation it seeks to remedy through clause 5.11 is infrequent and has only occurred in 26 instances (T368, L18-25).

The Board accepts the proposed revision on the basis of NTPC's explanation that any such funds would in essence act as an offset against otherwise delinquent accounts. The Board expects that NTPC will continue to make every reasonable effort to locate former customers who are owed security deposits and directs NTPC to publish a notice in a newspaper with circulation in the NWT one month prior to the six year anniversary date prior to the unclaimed deposit becoming the property of the Corporation.

13. OTHER MATTERS

13.1 2012 Actual Results

TGC submitted not having reliable actual data for the most recently completed year casts a shadow of a doubt as to the reasonableness of the 2012-2014 Test Year Revenue Requirements. This is not to suggest that 2012 actual results should simply replace 2012 forecasts. Rather, the use of 2012 results of operations is to assess the nature and extent of changes, if any, which may be required to the costs and revenues included in the Test Year 2013-2014 Revenue Requirements. [TGC Argument, P8, Para 24]

The TGC submits, by not providing the March 31, 2012 actual balance sheet data, the forecast year-end balances of Property, Plant and Equipment accounts, Accumulated Amortization as well as Deferral accounts will be different than the actual values, and hence, the amount of return and depreciation for the Test Years will be either over or under-stated. Neither the Corporation, nor customers, should benefit from the use of erroneous opening continuity balances. [TGC Argument, P8, Para 25]

Accordingly, TGC recommended that the Board direct NTPC to reflect the following actual Opening balances as at April 1, 2012 in its 2012-2014 Compliance Filing:

- *Rate base data – including Property Plant and Equipment, Accumulated/Depreciation, Contributions in Aid of Construction;*
- *2012 actual debt and interest rates;*
- *2012 actual opening balances of all deferral accounts; and the impact of all load forecast and revenue and expense accounts which vary from the 2012 filed-forecasts by more*

> *than 10% and which would have a bearing on the filed-for forecasts for the Test Years.* [TGC Argument, P 10-11, Para 28]

In its Reply submission, the TGC stated that when a hearing occurs well into a Test Year, the forecast nature of the regulatory model is distorted. In effect, the utility has the benefit of actual data and the regulator does not. It serves the interests of the regulatory model that the utility provide this actual information when available and that it update forecast balances in the GRA and compliance filing. This practice is commonly accepted in other jurisdictions, including Alberta. [TGC Reply, P6, Para 16]

In its Reply submission, NTPC submitted it does not support the TGC's request to update opening balances. NTPC states the premise of a GRA based on a future forward test year, particularly in light of the Board's direction that GRA's be filed as far as possible in advance of the actual test year starting, is inconsistent with incorporating actual data for the opening balances. Further, NTPC states, it has not completed this work to date; so, there is a time and cost implication for requiring these updates to be completed.

NTPC submitted that the actual opening balances are not expected to be materially different from the forecast test year opening balances used in the GRA. On the one item where a notable difference was expected, the long-term debt interest rate, NTPC states, it has already incorporated this update into the revised GRA numbers and requested approvals in Exhibit 13. [NTPC Reply, P31, L13-22]

Board Findings:

The Board notes NTPC's statement that incorporating actual data for the opening balances is not consistent with the premise of a GRA based on a future forward test year, particularly in light of the Board's direction that GRA's be filed as far as possible in advance of the actual test year starting. The Board also notes TGC's view that as the proceedings progress, the utility has the benefit of actual data whereas the regulator does not, and it serves the interests of the regulatory model for the utility to provide actual opening balances, a practice that is commonly accepted in other jurisdictions, including Alberta.

In the Board's view the updating of actual information for opening balances should be assessed on a case by case basis. In this instance, the Board notes the opening balance for plant in service as reflected in note 7 of the 2011/12 financial statements is $388.272 million. [Ex 22, Note 7] On the other hand, the opening balance for gross plant in Schedule 5.1 amounts to $395.313 million. The difference of about $7.0 million does not appear to bear out NTPC's submission that actual opening balances are not expected to be materially different from the forecast Test Year opening balances used in the GRA.

Given the foregoing difference in opening gross plant balance, the Board considers it appropriate, in this instance, to reflect the most current information in relation to actual balances for the period preceding the test period, in the Test Year forecasts in order to ensure the Test Year forecasts are not unduly misstated as a result of building upon incorrect balances.

The Board therefore, directs NTPC, at the time of the Compliance Filing Application, to update the opening balances for plant in service and accumulated amortization as well as the opening balances for deferral accounts and deferred cost balances, to reflect the recorded balances. If the updating of these balances results in the need to update any other related items, such as contributions or amortization expense, based on materiality considerations, NTPC should reflect such changes as well in the Compliance Filing Application. NTPC is directed, as part of its Compliance Filing Application, to provide reconciliations between the regulatory schedules and the 2011/12 financial statements with respect to any updated opening balances.

13.2 Minimum Filing Requirements

YK/HR submitted, NTPC has continued its practise of providing schedules and tables in PDF format only. In order to improve regulatory efficiency, and avoid future processes to secure analysis in Excel format, NTPC should be directed to provide, in future proceedings, all tables and schedules included in filings with the Board, in Excel format with formulae and links intact, in addition to the PDF schedules and tables already provided. YK/HR recommended that this be identified as a minimum filing requirement. [YK/HR Argument, P4-5, Para 16]

With respect to determination of minimum filing requirements, NTPC stated it is attentive to the Board letter dated June 20, 2012, informing of the Board's intention to commence the GRA Filing Manual process upon the conclusion of the current NTPC GRA. This process is intended to help develop specific Minimum Filing Requirements for future GRAs. NTPC submitted that YK/HR recommendations in regards to future filing requirements are premature and should instead be addressed as part of the future process envisioned by the Board.

Board Findings:

The Board considers it more efficient to deal with the minimum filing requirements as part of the GRA filing Manual process. Accordingly, the Board will defer any consideration of minimum filing requirements to that proceeding.

14. SUMMARY OF BOARD DIRECTIONS

Compliance Filing Application

1. NTPC is directed to remove the cost of the transmission line development study from each Test Year rate base, in its Compliance Filing Application.

2. The Board directs NTPC to provide as part of the Compliance Filing Application; details of all studies included under the category of feasibility studies and provide justification for why any additions to the feasibility studies account in the 2007/08 to 2010/11 period should be capitalized based on the guidance provided in Directive 18 from Decision 17-2009. At the same time, NTPC should also provide support showing how the amortization amounts in each Test Year were arrived at having regard to each study.

3. The Board considers disallowed assets should not be included in gross plant in service and in rate base. Accordingly, NTPC is directed to remove the net book value of disallowed assets from Test Year rate base in its Compliance Filing Application.

4. The Board considers that NTPC has not provided any analysis that would weigh and evaluate the qualitative and quantitative benefits of holding the proposed level of inventory in relation to the carrying costs. In the absence of such evidence, the Board will approve the inclusion of 50% of the proposed inventory in rate base in 2012/13 and 2013/14. Therefore, NTPC is directed to remove 50% of the cost of major spares and capital inventory from Test Year rate base in its Compliance Filing Application.

5. The Board directs NTPC to address the appropriate treatment and adjustments for any expenditures for components included in the Engine Overhaul Deferral Account, that are considered retirement units for amortization purposes, in its Compliance Filing Application.

6. The Board directs NTPC to include, in its Compliance Filing Application, annual brushing costs for each zone calculated based on the 5 actual year average brushing costs with due adjustment for inflation and any forecast scope changes.

7. BR.NTPC-7b) provided a detailed cost of debt calculation. NTPC is directed to file the calculation of the updated cost of debt (as updated in Exhibit 13) in the same format as in the BR.NTPC-7b) attachments, in Excel format, in support of its Compliance Filing Application.

8. The Board directs NTPC to provide, at the time of the Compliance Filing Application, evidence to support NTPC's view that the same rules apply to the lease as for NTPC's long-term debt and to provide evidentiary support for the view that DPC's cost of financing over the 65 year lease term should remain unchanged, notwithstanding the cost based nature of the lease.

9. NTPC is directed to address, at the time of the Compliance Filing Application, a method of recognizing the improvement in fuel efficiencies at Inuvik, in the rates for years commencing after the 2013/14 Test Year.

10. The Board directs NTPC that in its Compliance Filing Application, the ratio of fringe benefits for distribution and transmission is to be set at 37.06% for Test Years 2012/13 and 2013/14.

11. NTPC is directed to address how its practices regarding treatment of insurance proceeds and retirement of assets that are no longer in service, from gross plant in service, results in the correct amortization expense and amortization of reserve differences for the Test Years. If the Board's comments give rise to any corrections to the gross plant used for calculation of amortization expense, NTPC is directed to provide the corrected amortization expense at the time of the Compliance Filing Application.

12. The Board considers a move that is about 50% of the way towards the ASLs proposed by NTPC would provide an appropriate balance for the purposes of these proceedings. Accordingly, the Board directs NTPC to make a directional move in the Average Service Life parameter for the above noted accounts by reflecting ASLs of 35 years for account 341, 23 years for account 343 and 25 years for account 345, in its Compliance Filing Application.

13. The Board directs NTPC to provide, at the time of the Compliance Filing Application, details explaining the accounting entries involved in recording each of the affiliate costs/revenues (other than dividends), for GRA forecast purposes and for recording actual results for financial statement purposes.

14. NTPC is directed to identify the transfer pricing policy and how it was used for pricing shared services including overheads and, interest expense/recoveries, at the time of the Compliance Filing Application.

15. The Board directs that the GNWT contributions for 2012/13 and 2013/14 be recognized in the determination of rates for those years in NTPC's Compliance Filing Application.

16. NTPC is directed to address the 2014/15 phase in rate increase after giving effect to the Board's determinations in this Decision, at the time of the Compliance Filing.

17. With respect to the transitioning of the community of Norman Wells into the Thermal Zone, the Board, in the interest of rate stability, considers it appropriate to phase in rate increases for Norman Wells with annual increases of 7%, as may be required and, applicable to energy rates, until Norman Wells rates are fully transitioned to reflect the corresponding rates as the rest of the rates within the Thermal Zone. In order to achieve this, Norman Wells base rates should be adjusted to equal the corresponding Thermal Zone base rates. The 7% increase per year for Norman Wells should be given effect to by way of a credit rider applicable only to Norman Wells customers. The annual shortfall in revenue due to the Norman Wells credit rider will be collected by NTPC from the Thermal Zone in its entirety, including Norman Wells, by application of a recovery rider to all of the Thermal Zone base rates. The Board directs NTPC to propose rates and riders for Norman Wells and the Thermal Zone in accordance with this finding in its Compliance Filing Application.

18. The Board notes NTPC's cost allocation study by rate zone provided in BR.NTPC-22. For the purposes of the 2012/13 and 2013/14 Test Years, NTPC is directed to file, at the time of the Compliance Filing Application, an update to the cost allocations shown in BR.NTPC-22 for 2012/13 and 2013/14, in Excel format, reflecting the Board's determinations in this Decisions and showing:

    - How rate base, return, amortization expense and other components of revenue requirement were assigned or allocated by rate zone;
    - The proposed allocation of revenues from GNWT support by rate zone;

- The proposed revenues to be recovered through customer rates, by rate zone;
- How the proposed revenues by rate class would dovetail into the 2014/15 and 2015/16 rates phase in increases, by rate zone.

For the purposes of this update to BR.NTPC-22, the Taltson Zone should be considered separate from the Snare Zone.

19. NTPC is directed to file proposed rates designed to recover the proposed 2012/13 and 2013/14 revenues from customer rates reflecting the update to BR.NTPC-22 referred to above.

20. The Board also notes NTPC's acknowledgement that an Off-Road Track Digger is assignable to Inuvik. Accordingly, NTPC is directed to assign the cost of the off-Road digger to the Thermal Zone in the update to the cost allocations as set out in BR.NTPC-22, to be filed as part of the Compliance Filing Application.

21. The Board is not persuaded by NTPC's reasons for delaying the implementation of flat rates by zone for Government rate customer classes. The Board considers implementation of the revised electricity policy guidelines is not likely to impact NTPC's overall rate proposals or the rates for non-Government customers. Accordingly, NTPC is directed to propose, in the Compliance Filing Application, a flat Government rate by rate class and by zone that recovers the same revenue for the Government class as the proposed community based Government rates, for each zone. The Board considers this will accomplish the goal of simplified rates and a flat Government rate by class in each zone.

22. The Board therefore directs NTPC, at the time of the Compliance Filing Application, to update the opening balances for plant in service and accumulated amortization as well as the opening balances for deferral accounts and deferred cost balances, to reflect the recorded balances. If the updating of these balances results in the need to update any other related items, such as contributions or amortization expense, based on materiality considerations, NTPC should reflect such changes as well in the Compliance Filing Application.

23. NTPC is directed, as part of its Compliance Filing Application, to provide reconciliations between the regulatory schedules and the 2011/12 financial statements with respect to any updated opening balances.

Next GRA

24. The Board directs NTPC to provide business cases in support of major capital projects forecast to be added to rate base, at the time of the next GRA. The Board finds the list of items to be addressed in business cases as set out by YK/HR provides a reasonable template for structuring business cases. For the purpose of preparing business cases, the Board accepts YK/HR recommendation that the project cost threshold for business cases be set at $400,000.

25. NTPC is directed to prepare business cases for capital projects meeting the above threshold and are to commence after March 31, 2013 and, be prepared to provide detailed explanations for variances between budget and actual costs based on post completion reports.

26. The Board directs NTPC to provide a post completion report with respect to the Inuvik Diesel Conversion Project, at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in the planning, budgeting and execution of the project and, providing detailed explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant.

27. The Board directs NTPC to provide a post completion report with respect to the Bluefish Dam replacement project at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in the planning, budgeting and execution of the project and, providing detailed explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant.

28. The Board is concerned that inclusion of deferred costs under the category of deferral accounts and under the category of plant in service can result in confusion and errors in the testing and evaluation of such costs. Accordingly, NTPC is directed to include deferred costs under an appropriate FERC account at the time of the next GRA.

29. The Board directs NTPC to provide a cash working capital calculation based on a sampling of leads and lags at the time of the next GRA. This means any revenues related to late payment charges should also be included in other revenues.

30. Noting the uncertainties over the split in the accumulated amortization balance discussed above, the Board directs NTPC to provide evidence to support the split between accumulated amortization applicable to original cost

of assets and accumulated amortization applicable to net salvage at the time of the next GRA.

31. The Board continues to be concerned by an RSF mechanism which allows pass through of all diesel costs as this may not provide the appropriate incentive for NTPC to maximize use of the hydro resource. The Board directs NTPC to address the feasibility of NTPC assuming forecast risk on diesel volume variances for the Snare Zone at the time of the next GRA.

32. The Board directs NTPC to examine the following refinements with respect to its UPC forecast methodology for the purposes of the next GRA:

- For those communities where temperature normalization data is available, NTPC is to carry out regression analyses for all temperature sensitive sales, using degree days, trend variable(s) and any other relevant variables to develop a reasonable estimate of forecast UPC.

- For those communities where temperature normalization data is not available, NTPC is to use a straight 5 year average UPC over the most recent recorded (actual) years and use the actual growth rate over the same recorded years to project growth for the forecast years.

33. The Board notes YK/HR concern that capital additions such as Line Tools, Hot Sticks, Truck equipment, and major tool purchases, Type 6 work as well as certain vehicle and machinery purchases are budgeted at corporate; yet the actual costs are eventually recorded in the communities that are served. The Board agrees the type of costs referred to by YK/HR are not common costs but rather, zone specific costs and should be assigned to each zone on a forecast basis using reasonable assumptions. NTPC is directed to reflect this direction in future GRA filings.

September 30, 2014 Phase 2 GRA Filing

34. In order to continue the rate phase in by rate zone, the Board considers it necessary for NTPC to conduct a fully allocated zone based cost of service study and structure the increases in 2015/16 having regard to this study. Accordingly, NTPC is directed to file a zone-based, fully allocated cost of service study based on the 2013/14 approved revenue requirement together with proposed rates targeting 100% revenue to cost ratios by rate zone in 2015/16, subject to other rate design criteria. The Board will refer to this as the 2015/16 Phase 2 Application. This Phase 2 Application is to be filed by September 30, 2014 which would allow at least 6 months processing time prior to the commencement of the 2015/16 fiscal year.

35. The Board directed NTPC to file a 2015/16 Phase 2 Application in order to establish appropriate revenue to cost ratios by rate zone. Consistent with Directive 14, the Board considers it appropriate to also target revenue to cost ratios of 100% by rate class, subject to other rate design criteria. Accordingly, NTPC is directed to file a cost of service study based on the 2013/14 approved revenue requirement, showing the allocation of costs by rate class and the design of proposed rates by rate class, for 2015/16, by September 30, 2014.

15. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. The Board directs NTPC to provide to the Board and interested parties a Compliance Filing Application reflecting the findings and directions in this Decision, including proposed revenue requirements for the 2012/13 and 2013/14 Test Years, rates designed to recover the customer portion of revenues for 2012/13, 2013/14 and 2014/15 and a rate rider to recover any shortfall arising from late implementation of interim rates in 2012/13, within 45 days of this Decision.

2. The Board directs NTPC to provide as part of the Compliance Filing Application a working model, in Excel format, of all GRA schedules relating to the establishment of rate base, return, revenue requirement, revenues and revenue deficiencies and all relevant supporting schedules.

3. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

Joe Acorn

Joe Acorn
Chairman

Dated January 21, 2013