

Appendix A

2016 Depreciation Study



2016 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL
RATES APPLICABLE TO PLANT IN SERVICE
AS OF MARCH 31, 2015

Prepared by:



*Excellence Delivered **As Promised***

NORTHWEST TERRITORIES POWER CORPORATION
Hay River, Northwest Territories

2016 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES APPLICATION TO
PLANT IN SERVICE AS OF MARCH 31, 2015

GANNETT FLEMING CANADA ULC

Calgary, Alberta

**Gannett Fleming***Excellence Delivered **As Promised***

June 20, 2016

Northwest Territories Power Corporation
4 Capital Drive
Hay River, NT
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Attention: Ms. Belinda Whitford CPA, CA
Chief Financial Officer

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric generation, transmission, distribution, and general plant assets of Northwest Territories Power Corporation ("NTPC") as of March 31, 2015. Our report presents a description of the methods used in the estimation of depreciation, the statistical analyses of service life and the summary and detailed tabulations of annual and accrued depreciation.

The calculated annual depreciation accrual rates presented in the report are applicable to plant in service as of March 31, 2015. The depreciation rates are based on the straight-line whole life method using the average service life procedure, with any accumulated depreciation variances in excess of 5% being amortized over the estimated remaining life of the assets. An annual review of the depreciation rates using the same estimates and methods is recommended.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

LARRY E. KENNEDY
Vice President

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NORTHWEST TERRITORIES POWER CORPORATION DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Northwest Territories Power Corporation's ("NTPC") request, Gannett Fleming Canada ULC ("Gannett Fleming") conducted a depreciation study related to the electric generation, transmission, distribution, and general plant assets as of March 31, 2015. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking objectives.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a whole life basis. The calculations were based on attained ages and estimated average service life, and forecasting net salvage characteristic for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation as at 2015 are amortized over the remaining life of assets.

The previous depreciation study completed by Gannett Fleming in 2012 incorporated a "pause" approach to accruing for the future costs of removal of assets. Gannett Fleming remains of the view that net salvage is an important component of depreciation rates. NTPC is adopting a phase-in approach to restarting the accrual for future cost of removal. As such, NTPC has directed Gannett Fleming to incorporate net salvage percentages recognizing the "phased-in" reimplementation of net salvage accruals in this study. With the exception of the reinstatement of net salvage accruals, NTPC's accounting policy has not changed since the last depreciation study was prepared.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric generation, transmission, distribution and general plant in service as of March 31, 2015 as summarized by Tables 1 and 2 of the study by account detail. Supporting data and calculations are provided as well within the study.

Finally, this study results in an annual depreciation expense accrual of \$15.8 million when applied to depreciable plant balances as of March 31, 2015. The report study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST	ANNUAL ACCRUAL	
	\$'s	% 's	\$'s
(1)	(2)	(3)	(4)
OTHER UTILITY PROPERTY	7,562,371	3.43	259,482
HYDRO PLANT	162,768,402	1.72	2,799,926
DIESEL PLANT	167,072,870	4.43	7,408,672
TRANSMISSION PLANT	50,893,431	2.74	1,396,607
DISTRIBUTION PLANT	34,739,544	2.25	783,342
GENERAL	43,060,384	7.43	3,198,614
TOTAL PLANT IN SERVICE	466,097,002	3.40	15,846,643

PART I. INTRODUCTION

NORTHWEST TERRITORIES POWER CORPORATION
2016 DEPRECIATION STUDY
PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Northwest Territories Power Corporation (NTPC), to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of electric generation, transmission, distribution, and general plant at March 31, 2015. The rates and amounts are based on the straight line whole life method of depreciation with a separate amortization of the variance between the book depreciation reserve and the calculated accrued depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to electric generation, transmission and distribution plant in service as of March 31, 2015.

The service life and net salvage estimates resulting from the study were based on: informed engineering judgment which incorporated analyses of historical plant retirement data as recorded through 2015; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the electric utility industry, including knowledge of service lives and net salvage estimates used for other electric companies.

PLAN OF REPORT

Part I Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II. Development of Depreciation Parameters, presents descriptions of the methods used in the service life and net salvage studies. Part III. Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation. Part IV. Results of Study, presents summaries by depreciable group of annual and accrued depreciation. Part V presents the results of the Retirement Rate Analysis and Service Life Statistics and Part VI presents Net Salvage Analysis. Detailed tabulations of annual and accrued depreciation is presented in Part VII of this report. An overview of Iowa curves and the Retirement Rate Analysis are set forth

in Appendix A of the report. An overview of the net salvage analysis is presented in Appendix B of this report.

BASIS OF THE STUDY

Depreciation

For most accounts, the annual and accrued depreciation were calculated by the straight line method using the average service life procedure. For certain General Plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives and salvage. Variances between the calculated accrued depreciation or amortization and the book accumulated depreciation are amortized over the composite remaining life of each account.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Gannett Fleming has determined an amortization amount to correct the present variance with the calculated accrued depreciation, ("theoretical reserve"), over the composite remaining life of each account. Table 2A presented in Part IV of the report sets forth the amortization of the reserve variance at the account level. This adjustment mechanism, whether determined separately as an amortization amount or incorporated in the calculation of remaining life accruals, is widely-accepted. An explanation of the monitoring of the accumulated depreciation reserve and the calculation of the true-up provision is presented beginning on page III-5 of the report.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. Many electric utilities in North America have received approval to adopt amortization accounting for these accounts.

Service Life and Net Salvage Estimates

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for electric generation, transmission and distribution plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

PART II. DEVELOPMENT OF DEPRECIATIONS PARAMETERS

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

The calculation of annual and accrued depreciation based on the straight line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed in Part III of this report.

ESTIMATION OF SURVIVOR CURVES

Survivor Curves

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and relative height of the modes. The left-moded curves are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical-moded curves are those in which the greatest frequency of retirement occurs at average service life. The right-moded curves are those in which the greatest frequency occurs to the right of, or after, the average service life. The origin-moded curves are those in which the greatest frequency of retirement occurs at the origin, or immediately after age 0. The letter designation of each family of curves (L, S, R or O) represents the mode of the associated frequency curve with respect to the average service life. The numerical subscripts represent the relative heights of the modes of the frequency curves within each family.

A discussion of the general concept of survivor curves and retirement rate method is presented in Appendix A of this report.

Survivor Curve and Net Salvage Judgments

The survivor curve and net salvage estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel and on the knowledge Gannett Fleming developed through the completion of numerous electric utility studies.

The estimates of net salvage were based in part on historical data related to actual retirement activity for the years 2001 through 2015 for most accounts. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Percentages of the cost of plant retired were calculated for each component of net salvage on both annual and five-year moving average bases.

The net salvage estimates are expressed as percentages of the cost of plant.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by

Gannett Fleming in the determination of the average service life and net salvage estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

Account 332.00 – Hydro Plant – Reservoirs, Dams and Waterways – represents 15% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1949 through 2015 were analyzed by the retirement rate method. The original life table as provided on pages V-12 and V-13, and as plotted on page V-11, show increasing retirement ratios beginning at age 48.5 with a steep increase in the following years, indicating a higher mode curve.

The Iowa curve matching procedures employed by Gannett Fleming resulted in an Iowa 65-R1.5 being considered the best fit to the historic retirement trends with a residual measure of 9.82¹. The Iowa 65-R1.5 represents a shorter life estimate than the currently used Iowa 100-R3, and is significantly shorter than the Canadian peer range of 100 - 125 year estimates.

The operational staff discussions did not indicate any reason to believe that the plant currently in service should have any significant changes from the plant in service as of the currently approved rates. There are no plans to retire the reservoirs, dams or waterways prior to 100 years in any surviving dam structure at this point. Furthermore, the plant in service is expected to behave similarly to other Canadian peer companies.

As the Iowa 100-R3 is consistent with operational staff interviews and is consistent with peer Canadian electric generation companies, the Iowa 100-R3 is forecast to be representative of the anticipated future retirement activity. Consequently, the continuation of the currently approved 100-year average service life is reasonable.

A net salvage study is presented for this account on page VI-5 which reviewed the net salvage characteristics resulting from the retirement experience for a 13-year period from 2003 through 2015. Over this historic period, the company has incurred \$2.7 million to retire \$4.8 million of original cost of investment and has not made any recovery from

¹ A Residual Measure is based on a least squares solution of the differences between the stub curve (and original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve. The criterion of "goodness of fit" is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The Residual Measure, or standard error of estimate is the square root of this mean square. As a result, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points.

the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 57 percent far exceeds the previously recommended negative 5 percent.

Gannett Fleming also reviewed the three-year rolling average of the historic net salvage requirements and note that only three of the past 11 three-year rolling averages have been lower than negative 30 percent. Gannett Fleming views that a significantly more negative net salvage percentage is required based on the last 12 years of historic experience.

As the net salvage percentage of negative 30 provides a good representation of historical net salvage percentages and is consistent with operational staff interviews, the percentage of negative 30 is forecast to be representative of the anticipated future net salvage activity and is recommended in this study.

Account 343.00 – Diesel Plant - Prime Movers - represents 14% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original life table as provided on pages VI-33 and VI-34, and as plotted on page VI-32, indicates significant retirement ratios beginning in the first 10 years of the account's life and continues through to approximately age 30. By age 37.5 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 37.5. The Iowa curve matching procedures employed by Gannett Fleming resulted in an Iowa 21-S2.5 being considered the best fit to the historic retirement trends with a residual measure of 3.43.

Interviews with company management indicated that company policy regarding engine retirements in this account has changed since the last study. Previously engines were retired when they were replaced. However, recently it has been difficult to find compatible spare engines, requiring old engines to be refurbished and placed in storage for replacements. This will have a life lengthening impact on the assets in this account.

As the Iowa 23-R3 provides a reasonable interpretation of the historical data with a residual measure of 7.94 and is consistent with operational staff interviews, the Iowa 23-R3 is forecast to be representative of the anticipated future retirement activity and is recommended in this study.

A net salvage study is presented for this account on page VI-12 which reviewed the net salvage characteristics resulting from the retirement experience for a 14-year period from 2002 through 2015. Over this historic period, the company has incurred \$1.8 million to retire \$7.2 million of original cost of investment and has recovered \$.03 million from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 24 percent is in line with the previously recommended negative 25 percent net salvage.

As the net salvage percentage of negative 25 provides a good representation of historical net salvage percentages and is consistent with operational staff interviews, the percentage of negative 25 is forecast to be representative of the anticipated future net salvage activity and is recommended in this study.

Account 341.00 – Diesel Plant - Structures and Improvements - represents 9% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original survivor curves, as plotted on page V-26 show increasing retirement ratios beginning at an early age with a large increase at age 22.5, indicating a medium mode Iowa curve. After age 29.5, the plant exposed to retirement falls to below 1% of the account's total plant exposed to retirement, resulting in the retirement ratios and percentages surviving after age 29.5 being provided a significantly lesser amount of weight.

The previous Gannett Fleming study recommended a 30-S2.5 Iowa curve. The review of average service life estimates for the applicable peer companies of Canadian utilities indicated a range of lives from 25 to 50 years. It is the view of Gannett Fleming that 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 currently approved 30-S2.5 Iowa curve produces a residual measure of 11.31 through to age 20.5. In comparison, the Iowa 32-S2.5 as recommended in this study provides a good fit to the historic retirement pattern through the period of statistical reliance with a residual measure of 7.98 through age 29.5, is within the range of approved average service lives for comparable Canadian peer utilities, and is consistent with the expectation of the operational and management staff of NTPC.

A net salvage study is presented for this account on page VI-10 which reviewed the net salvage characteristics resulting from the retirement experience for a 14-year period from 2002 through 2015. Over this historic period, the company has incurred \$.7 million to retire \$1 million of original cost of investment and has recovered \$.006 million from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 73 percent is significantly higher than the previously recommended negative 25 percent net salvage.

Gannett Fleming views that a net salvage percentage of negative 35 provides a good representation of historical net salvage percentages and is consistent with operational staff interviews, the percentage of negative 35 is forecast to be representative of the anticipated future net salvage activity and is recommended in this study.

Account 333.00 – Hydro Plant - Water Wheels, Turbines and Generators - represents approximately 7% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-14, indicates a large increase in the retirement ratios beginning at age 19. After this point, the retirement ratios remain high through the life of this account.

Previously, this account had an approved life of 65-L1.5, which produces a residual measure of 14.58. Currently, the historic data is indicating an average service life of 43 years, with the peer analysis of Canadian utilities suggesting a life of 60 to 85 years. Given that the retirement rate analysis was based on a limited amount of retirement transactions, Gannett Fleming believes that the indicated trends must be viewed with some moderation, and that a reduction from 65 years to 45 years is not appropriate and is too dramatic in the circumstances of this account.

Conversations with NTPC personnel indicate that some of the retirement transactions in this account relate to generators at Taltson, which were retired early. There were also a number of assets that had to be retired early due to an increase in capacity at Snare Rapids. These conversations have indicated that this retirement of assets earlier than at Canadian peer companies is likely to occur again in the future and needs significant weighting when creating an average service life estimate.

Consequently, Gannett Fleming is of the view that a reduction in life is necessary for this account.

Giving consideration to all of the above, Gannett Fleming believes that 50-S2 is the best estimate to reflect the future retirement patterns of this account at this time. The 50-S2 produces a residual measure of 12.26 and provides the appropriate weighting of the historic retirement indications, the comments of the company management and operational staff, and the comparisons to Canadian peers. This account will need close monitoring in years to come to ensure that any further decreases in average service life are made.

A net salvage study is presented for this account on page VI-6 which reviewed the net salvage characteristics resulting from the retirement experience for a 12-year period from 2003 through 2015 including the estimate upcoming forecast costs of removal. Over this period, the company has incurred \$0.75 million to retire \$1.4 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 55 percent is significantly higher than the previously recommended negative 5 percentage.

As the net salvage percentage of negative 15 provides a good representation of historical net salvage percentages and is consistent with operational staff interviews, the percentage of negative 15 is forecast to be representative of the anticipated future net salvage activity and is recommended in this study.

Account 345.00 – Diesel Plant - Accessory Electric Equipment - represents approximately 5% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-37, shows retirement ratios which remain relatively consistent throughout the period to when the plant exposed to retirement falls below a level of 1% of the total plant exposed to retirement. Additionally the original life table as presented on pages V-38 and V-39 is based on a significant level of retirement activity, providing statistical relevance to the results of the retirement rate analysis.

The historical data indicates an Iowa Curve of 24-L3 which produces a residual measure of 4.66. Gannett Fleming and NTPC personnel agree that this account will

continue to retire assets in a similar fashion in the future. Consequently, the recommended Iowa 24-L3 curve is representative of the past mortality trends, is within the range experienced by the relevant Canadian peer companies and is consistent with management and operational expectations.

A net salvage study is presented for this account on page VI-14 which reviewed the net salvage characteristics resulting from the retirement experience for a 13-year period from 2002 through 2015 including the estimate upcoming forecast costs of removal. Over this period, the company has incurred \$0.6 million to retire \$2.1 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 28 percent is significantly higher than the previously recommended negative 10 percentage.

As the net salvage percentage of negative 10 provides a good representation of historical net salvage percentages and is consistent with operational staff interviews, the percentage of negative 10 is forecast to be representative of the anticipated future net salvage activity and is recommended in this study.

Account 342.00 – Diesel Plant - Fuel Holders, Producers and Accessories - represents approximately 5% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1961 through 2015 were analyzed by the retirement rate method. The original life table as presented on pages V-30 and V-31, and as plotted on page V-29 indicates a significant level of retirement activity beginning early in the account's life and continuing through to approximately age 27.5, at which point the plant exposed to retirement is less than 1% of the total plant exposed to retirement. The retirement analysis produced a better fit of the Iowa 22-R4 with a residual measure of 2.66, which is a significant reduction from the currently approved Iowa 30-L4 with a residual measure of 22.91.

The relevant comparable utilities have an average service life ranging from 23 years to 35 years. Internal NTPC personnel have indicated that many of the early retirements in this account are related to a program replacing single wall tanks with double walled tanks. Double walled tanks are expected to have a longer life than the original single walled tanks, which should have a life lengthening impact. NTPC personnel

indicate that the new double wall tanks should have a life of 30 years. Consequently, Gannett Fleming recommends maintaining the currently approved Iowa 30-L4.

A net salvage study is presented for this account on page VI-11 which reviewed the net salvage characteristics resulting from the retirement experience for a 13-year period from 2002 through 2015 including the estimate upcoming forecast costs of removal. Over this period, the company has incurred \$2.3 million to retire \$1.9 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 122 percent is significantly higher than the previously recommended negative 60 percentage.

As the net salvage percentage of negative 75 is a 25 percent increase in net negative salvage rate, Gannett Fleming believes that this is a reasonable step to take. Gannett Fleming recommends close monitoring of this account to recognize any future increases in net negative salvage that might occur.

Account 334.00 – Hydro Plant - Accessory Electric Equipment - represents approximately 5% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1960 through 2015 were analyzed by the retirement rate method. The original life table as provided on pages V-18 and V-19, and as plotted on page V-17, indicates a few specific but sporadic ages of retirement of investment, but very little on-going year-over-year retirement. Given the limited and sporadic nature of the historic retirement activity, Gannett Fleming did not place a large amount of weighting on the retirement rate analysis in the selection of the average service life estimate for this account.

Discussions with NTPC personnel and the professional judgment of Gannett Fleming led to the recommendation of a 40-R2.5. The previously approved Iowa curve for this account was 31-L2.5 which produces a residual measure of 11.65. Comparable Canadian peer companies have average service lives of 45 years. Discussions with NTPC personnel indicate that moving the average service life for this account to be more in line with Canadian peer utilities is reasonable. Consequently, Gannett Fleming recommends an increase in the average service life estimate to the Iowa 40-R2.5, with a residual measure of 2.41, be approved for this account.

A net salvage study is presented for this account on pages VI-7 which reviewed the net salvage characteristics resulting from the retirement experience for an 11-year period from 2004 through 2015. Over this period, the company has incurred \$0.24 million to retire \$0.25 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 96 percent is significantly higher than the previously recommended negative 2 percentage.

As the net salvage percentage of negative 20 provides a good representation of historical net salvage percentages and is consistent with operational staff interviews, the percentage of negative 20 is forecast to be representative of the anticipated future net salvage activity and is recommended in this study.

Account 331.00 – Hydro Plant - Structures and Improvements - represents approximately 5% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original life table as provided on pages V-9 and V-10, and as plotted on page V-8, indicates that at this point, there have been only a limited amount of retirements in this account.

The retirement rate analysis gives weight to a number of early retirements, many of which were part of the Bluefish Dam project. This retirement project gives historic indications of a shorter life, which the operations and management staff believe will not be indicative of the future activity for this account. NTPC personnel believe that the structures and improvements associated with the new Bluefish Dam will last 100 years at minimum. Consequently, Gannett Fleming views that the continuation of the 100-year average service life estimate is reasonable. As such the Iowa 100-R3 is recommended in this study.

A net salvage study is presented for this account on pages VI-4 which reviewed the net salvage characteristics resulting from the retirement experience for an 11-year period from 2004 through 2015. Over this period, the company has incurred \$0.19 million to retire \$0.15 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage

percentage of negative 132 percent is significantly higher than the previously recommended negative 5 percentage.

As the net salvage percentage of negative 30 provides a good representation of the limited historical net salvage percentages and is consistent with operational staff interviews, the percentage of negative 30 is forecast to be representative of the anticipated future net salvage activity and is recommended in this study.

Account 354.00 – Transmission Plant - Towers and Fixtures - represents approximately 3% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-47 shows a lack of retirement history to date. Consequently, Gannett Fleming was unable to rely on the historical data in recommending an Iowa curve for this account.

Gannett Fleming compared the life and historical experience of this account against a number of relevant Canadian peer utilities. This review indicated that the Canadian peer utilities have exhibited average service lives of between 50 and 85 years. Based on the lack of historic retirements in this account, Gannett Fleming has placed a large weighting on the opinions of the internal NTPC staff in arriving at the recommended life estimates. Given the lack of historic retirements Gannett Fleming recommends maintaining the currently approved 65-R4 Iowa curve.

To date NTPC has not retired any significant investment in Transmission Towers. As such, there is no historic retirement information upon which a net salvage percentage can be developed. However, Gannett Fleming has developed a number of net salvage percentage estimates for electric transmission towers throughout Canada. Based on Gannett Fleming's experience a net salvage percentage of at least negative 25 percentage will be required for the removal of the transmission towers when they are removed. The NTPC operational staff agreed that the recommended negative 25 percent is reasonable at this time.

Account 353.00 – Transmission Plant - Station Equipment - represents approximately 3% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original life tables presented on pages V-45 and V-46, and as plotted

on page V-44 show moderate levels of retirement activity beginning at approximately age seven. Based on this moderate level of retirement activity the retirement rate analysis provided an indication of an Iowa 29-R2.5 with a residual measure of 5.48 for this account. This statistical indication of the Iowa 29-R2.5 would indicate a slight reduction in the average service life from the currently approved Iowa 31-L1.5.

Gannett Fleming compared the life and historical experience of this account against a number of relevant Canadian peer utilities. This review indicated that the Canadian peer utilities have exhibited average service lives between 45 to 47 years. Based on discussions with operational and management staff of NTPC, the indications are that the future life characteristic of the account should not be materially different than the historic trends. Therefore, while comparable Canadian peer utilities do appear to have longer average lives, the recommended 29-R2.5 provides some weighting to the Canadian peer trends, but also recognizes the indications of the company staff that the future trends will be consistent with the historic retirement patterns.

A net salvage study is presented for this account on page VI-16 which reviewed the net salvage characteristics resulting from the retirement experience for a 12-year period from 2003 through 2015 including the estimate upcoming forecast costs of removal. Over this period, the company has incurred \$0.5 million to retire \$1.3 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 42 percent is higher than the previously recommended negative 10 percentage.

As the net salvage percentage of negative 20 is a 100 percent increase in net negative salvage rate, Gannett Fleming believes that this is a reasonable step to take. Gannett Fleming recommends close monitoring of this account to recognize any future increases in net negative salvage that might occur.

Account 364.00 – Distribution Plant - Poles, Towers and Fixtures - represents approximately 3% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1961 through 2015 were analyzed by the retirement rate method. The original life table as presented on pages V-69 and V-70, and as plotted on page V-68 of this report indicate only a modest level of historic retirement activity.

Gannett Fleming reviewed the relevant Canadian peer industry comparable service lives in making a recommendation for this account. The mean average service life for this account across six comparable utilities is 45 years. This is in line with the previously approved Iowa 45-R4 with a residual measure of 18.84. After consulting with NTPC personnel, Gannett Fleming is recommending a slightly longer life than industry comparable information due to the operations and maintenance policies of NTPC. Assets are maintained and repaired as many times as possible in order to extend the life. Gannett Fleming relied heavily on industry comparable information but extended the life to account for policies that are unique to NTPC. Consequently, Gannett Fleming recommends an increase in the average service life estimate to the Iowa 50-R2.5, with a residual measure of 8.27, be approved for this account. A net salvage study is presented for this account on page VI-20 which reviewed the net salvage characteristics resulting from the retirement experience for a 13-year period from 2002 through 2015. Over this period, the company has incurred \$0.08 million to retire \$0.4 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 23 percent is approximately the same as the previously recommended negative 25 percent net salvage.

Gannett Fleming reviewed the relevant Canadian peer industry comparable information in making a recommendation of net salvage percentage for this account. The net salvage percentages range from negative 45 to negative 75 percent. As the net salvage percentage of negative 25 is reasonably close to the historic average and is significantly lower than Canadian peer utilities, Gannett Fleming believes it is indicative of future net salvage percentages. Consequently, Gannett Fleming recommends a net salvage percentage of negative 25.

Account 336.00 – Hydro Plant - Roads, Railroads and Bridges - represents approximately 2% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-23 shows a lack of significant retirement activity. Consequently, Gannett Fleming did not place any weight on the historical data for this account.

This account has a currently approved Iowa curve of 75-R4. Gannett Fleming compared this account to three Canadian peer utilities, with a range of average service lives of 50 to 75 years. Discussions with NTPC personnel indicated that a life of approximately 50 years would be correct. Due to the limited retirement activity suggesting a shorter life, the range of Canadian peer comparable information and discussions with NTPC personnel, Gannett Fleming recommends a life of Iowa 50-R5.

A net salvage study is presented for this account on page VI-9 which reviewed the net salvage characteristics resulting from the retirement experience for a 4-year period from 2001 through 2015. Over this period, the company has incurred \$0.3 million to retire \$0.7 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 37 percent is significantly higher than the previously recommended negative 2 percentage.

As the net salvage percentage of negative 5 provides a conservative representation of historical net salvage percentages and is consistent with operational staff interviews, the percentage of negative 5 is forecast to be representative of the anticipated future net salvage activity and is recommended in this study.

Account 356.00 – Transmission Plant - Overhead Conductors and Devices - represents approximately 2% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1962 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-55 indicates a lack of retirement history at this time. Consequently, Gannett Fleming did not rely on the statistical analysis for this account.

The currently approved Iowa curve for this account is a 60-R4. However, the industry comparable utilities have a range of average service lives from 50 to 80. This, combined with discussions with NTPC staff, indicates that the average service life for this account should not be changed. Consequently, Gannett Fleming recommends maintaining a 60-R4 Iowa curve for this account at this time, which is consistent with the peer trend of Canadian utilities and with the expectations of internal NTPC management and operational staff.

A net salvage study is presented for this account on page VI-18 which reviewed the net salvage characteristics resulting from the retirement experience for a 6-year period from 2009 through 2015. Over this period, the company has incurred \$0.1 million to retire \$0.27 million of original cost of investment and has not made any recoveries from the reuse of the assets or through sale proceeds. As such, this historic net salvage percentage of negative 39 percent is higher than the previously recommended negative 25 percent net salvage.

Gannett Fleming reviewed the relevant Canadian peer industry comparable information in making a recommendation of net salvage percentage for this account. The net salvage percentages range from negative 20 to negative 50 percent. As the net salvage percentage of negative 25 is reasonably close to the historic average and is significant lower than Canadian peer utilities, Gannett Fleming believes it is indicative of future net salvage percentages. Consequently, Gannett Fleming recommends a net salvage percentage of negative 25.

Account 390.02 – Structures and Improvements – Other Small Structures - represents approximately 2% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1959 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-92, shows retirement ratios which remain relatively consistent throughout the period to when the plant exposed to retirement falls below a level of 1% of the total plant exposed to retirement. Additionally the original life table as presented on pages VI-96 and VI-97 is based on a significant level of retirement activity, providing statistical relevance to the results of the retirement rate analysis.

The historical data indicates an Iowa curve of 18-L5. NTPC personnel believes that the assets in this account are likely to live longer than this. Some of the retirements included in the retirement rate analysis are due to the acquisition of another company and the method of integrating the financial assets of this company. Consequently, the historical data fit is too short. The recommended 25-R1.5 curve is consistent with management and operational expectations.

Account 344.00 – Diesel Plant - Generators - represents approximately 2% of the depreciable plant studied. Historical retirements, additions and other plant transactions

for the period 1970 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-35 shows a lack of significant retirement activity. Consequently, Gannett Fleming did not place any weight on the historical data for this account.

This account has a currently approved Iowa curve of 28-R4. Discussion with NTPC personnel does not indicate a reason to change the life at this time. Consequently, Gannett Fleming recommends maintaining the life at Iowa 28-R4.

A net salvage study is presented for this account on page VI-13 which reviewed net salvage characteristics resulting from the retirement experience for a 10-year period from 2005 through 2015. As there is a lack of historic net salvage transactions, Gannett Fleming recommends maintaining the current estimate of negative 5 percentage net negative salvage.

Account 397.00 – General Plant – Communication Equipment - represents approximately 2% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1967 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page IV-103 shows a lack of significant retirement activity. Consequently, Gannett Fleming did not place any weight on the historical data for this account.

This account has a currently approved Iowa curve of 20-R3. Discussion with NTPC personnel does not indicate a reason to change the life at this time. Consequently, Gannett Fleming recommends maintaining the life at Iowa 20-R3.

Account 368.00 – Distribution Plant – Line Transformers - represents approximately 1% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1949 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-78, shows a large increase in the retirement ratios beginning at age 12.5. After this point, the retirement ratios remain consistent through the life of this account.

Previously, this account had an approved life of 40-S3 which produces a residual measure of 30.71. Currently, the historic data is indicating an average service life of 57-L4 which produces a residual measure of 3.34, with the peer analysis of Canadian utilities suggesting a life of 27 to 45 years. Given that the assets in this account are generally

newer than those of the Canadian peer comparables and that the climate of the Northwest Territories is drier and less corrosive, Gannett Fleming believes that the Canadian peer comparables must be viewed as not indicative of the life for NTPC assets. Consequently, Gannett Fleming recommends an Iowa 50-R5, with a residual measure of 7.60, for this account.

Gannett Fleming does not recommend any net salvage percentage at this time.

Account 131.00 – Other Utility Property – Residual Heat System - represents approximately 1% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1994 through 2015 were analyzed by the retirement rate method. The original life table as presented on page V-7, and as plotted on page V-6 of this report indicate only a modest level of historic retirement activity.

Previously, this account had an approved life of 25-R2 which produced a residual measure of 12.92. As there are limited Canadian peer comparables for this account, Gannett Fleming relied on the minimal retirement history and discussions with NTPC personnel. Gannett Fleming recommends increasing the life of this account to Iowa 28-R4, which results in a residual measure of 1.12.

Gannett Fleming does not recommend any net salvage percentage at this time.

Account 396.00 – General Plant - Power Operated Equipment - represents approximately 1% of the depreciable plant studied. Historical retirements, additions and other plant transactions for the period 1973 through 2015 were analyzed by the retirement rate method. The original survivor curve, as plotted on page V-98, shows retirement ratios which remain relatively consistent, with one large year of significant retirement activity at age 17.5, throughout the period to when the plant exposed to retirement falls below a level of 1% of the total plant exposed to retirement. Previously, this account had an approved life of 27-S1.5 with a residual measure of 18.55. As there are limited Canadian peer comparable estimates for this account, Gannett Fleming relied on discussions with NTPC personnel. Consequently, Gannett Fleming recommends maintaining the life of this account at Iowa 27-S1.5.

A net salvage study is presented for this account on pages VI-34 which reviewed net salvage characteristics resulting from the retirement experience for a 13-year period from 2002 through 2015. As there is a lack of historic net salvage transactions, Gannett

Fleming recommends maintaining the current estimate of positive 15 percentage net salvage.

Account 390.01 – General Plant – Hay River Office Buildings - represents approximately 1% of the depreciable plant studied. The recommended average service life for this account was based on the experience of Gannett Fleming and on the views of the operational and management staff at NTPC.

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

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CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, Average Service Life (ASL) and Equal Life Group (ELG).

In the average service life procedure, the rate of annual depreciation is based on the average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the ELG procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

In the determination of the depreciation rates in this study, the use of the average service life procedure has been continued.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. The accounts and their amortization periods are as follows:

<u>ACCOUNT</u>	<u>TITLE</u>	AMORTIZATION PERIOD, <u>YEARS</u>
351.00	TRANSMISSION PLANT – CLEARING LAND AND LAND RIGHTS	65
382.00	COMPUTER HARDWARE	5
383.00	COMPUTER SOFTWARE	5
391.00	OFFICE FURNITURE AND EQUIPMENT	15
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	15
395.00	LABORATORY EQUIPMENT	25
398.00	MISCELLANEOUS EQUIPMENT	15
399.00	OTHER TANGIBLE PLANT	20

For the purpose of calculating annual amortization amounts as of March 31, 2015, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

NTPC PHASED-IN RE-IMPLEMENTATION OF NET SALVAGE ACCRUALS

Gannett Fleming has in this depreciation study continued to recommend the inclusion of appropriate net salvage percentages in the requested depreciation expense. The recommended net salvage percentages have been identified and discussed in Part II of this report and are also identified on Table 1B at page IV-6. However, NTPC has directed Gannett Fleming to develop depreciation rates based on a phased-in re-implementation of the recommended net salvage percentages.

The amount of annual depreciation expense to be phased-in to restart of the net salvage accruals was determined by NTPC to be approximately \$550,000. This amount was provided to Gannett Fleming to use in the development of the phased-in net salvage accrual rates as displayed in Table 1B of this report. Gannett Fleming notes that this phased in approach is only applicable in the circumstances of this current depreciation study and that the full implementation of the net salvage accruals will be required in the next depreciation study.

Based on the request of NTPC to develop the phased-in net salvage accruals, Gannett Fleming developed a series of phased-in net salvage percentages to use in the depreciation rate calculations. In the development of the phased in net salvage percentages, Gannett Fleming gave specific consideration to the following:

- The recommended net salvage percentages associated with long life accounts were phased in to a greater degree than short life accounts. In this manner the impact of the future net salvage recovery is spread out over a longer remaining period than would be the case with shorter life accounts.
- The phased-in net salvage percentage was limited to a maximum percentage of negative 10 percent.
- The accounts where there is a positive net salvage percentage requirement where not phased-in.

The following chart provides the Gannett Fleming recommended net negative salvage percentages, and the phased-in net negative salvage percentages for each account where a net salvage percentage is required.

Account	Gannett Fleming Recommended Net Salvage Percentages	Phased-in Net Salvage Percentages
121.00 – Wind Turbines	-15	-10
331.00 – Structures and Improvements	-30	-5
331.00 – Reservoirs, Dams and Waterways	-30	-5
333.00 – Water Wheels, Turbines and Generators	-15	-5
334.00 – Accessory Electric Equipment	-20	-5
335.00 – Miscellaneous Power Plant Equipment	-10	-8
336.00 – Roads, Railroads and Bridges	-5	-5
341.00 – Structures and Improvements	-35	-8
342.00 – Fuel Holders, Producers and Accessories	-75	-10
343.00 – Prime Movers	-25	-8
344.00 – Generators	-5	-5
345.00 – Accessory Electric Equipment	-10	-5
353.00 – Station Equipment	-20	-5
354.00 – Towers and Fixtures	-25	-5
355.00 – Poles and Fixtures	-25	-5
356.00 – Overhead Conductors and Devices	-25	-5
364.00 – Poles, Towers and Fixtures	-25	-5
365.00 – Overhead Conductors and Devices	-25	-5
369.00 – Services	-10	-5

MONITORING OF BOOK ACCUMULATED DEPRECIATION

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics and net salvage materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation. Given the phased in approach to the reinstatement of the depreciation accruals for net salvage, a true-up calculation for the net salvage accrual has not been included in the recommended depreciation rates.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual equal life group remaining lives in accordance with the following equation:

$$\text{Composite Remaining Life} = \frac{\sum \left(\frac{\text{Book Cost}}{\text{Life}} \times \text{Remaining Life} \right)}{\sum \frac{\text{Book Cost}}{\text{Life}}}.$$

The book costs and lives of the several equal life groups, which are summed in the foregoing equation, are defined by the estimated future survivor curve. Inasmuch as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$\text{Composite Remaining Life} = \frac{\sum \text{Whole Life Future Accruals}}{\sum \text{Whole Life Annual Accruals}}$$

or

$$\text{Composite Remaining Life} = \frac{\sum \text{Book Cost} - \text{Calc. Reserve}}{\sum \text{Whole Life Annual Accrual}}.$$

PART IV. RESULTS OF STUDY

PART IV. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line method, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in the section beginning on page V-2 of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which were plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of March 31, 2015 are presented in account sequence starting on page VII-2 of the

supporting documents. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual.

NORTHWEST TERRITORIES POWER CORPORATION
TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, CALCULATED ANNUAL AND ACCRUED DEPRECIATION AS OF MARCH 31, 2015
PHASED IN NET SALVAGE LIFE

ACCOUNT	DESCRIPTION (1)	SURVIVOR CURVE (2)	ORIGINAL COST AS OF MARCH 31, 2015 (3)	ANNUAL RATE (4)	CALCULATED DEPRECIATION ANNUAL AMOUNT (5)	CALCULATED ACCRUED (6)	ANNUAL PROVISION FOR TRUE-UP (7)	TOTAL DEPRECIATION EXPENSE (8)=(5)+(7)	TOTAL DEPRECIATION RATE (10)=(8)/(3)
OTHER UTILITY PROPERTY									
118.00	SOLAR PANELS	25-R3	1,552,427	4.00	62,097.00	148,774	4,899	66,996	4.32
121.00	WIND TURBINES	40-R3	353,263	2.50	8,832.00	131,149	(19,171)	(10,339)	(2.93)
131.00	RESIDUAL HEAT SYSTEM	28-R4	5,656,681	3.57	201,943.00	1,707,454	0	201,943	3.57
	TOTAL OTHER UTILITY PROPERTY		7,562,371	3.61	272,872.00	1,987,377	(14,273)	258,599	3.42
HYDRO PLANT									
331.00	STRUCTURES AND IMPROVEMENTS	100-R3	22,598,497	1.00	225,985.00	5,768,142	(15,794)	210,191	0.93
332.00	RESERVOIRS, DAMS AND WATERWAYS	100-R3	70,279,438	1.00	702,794.00	9,878,668	45,269	748,063	1.06
333.00	WATER WHEELS, TURBINES AND GENERATORS	50-S2	32,145,105	2.00	642,902.00	10,041,424	106,257	749,159	2.33
334.00	ACCESSORY ELECTRIC EQUIPMENT	40-R2.5	22,977,232	2.50	574,431.00	7,320,954	(61,915)	512,516	2.23
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	20-R2	3,533,123	4.86	171,610.00	2,045,025	(40,060)	131,550	3.72
336.00	ROADS, RAILROADS AND BRIDGES	50-R5	11,235,007	2.00	224,700.00	4,846,549	91,478	316,178	2.81
	TOTAL HYDRO PLANT		162,768,402	1.56	2,542,422.00	39,700,762	125,235	2,667,667	1.64
DIESEL PLANT									
341.00	STRUCTURES AND IMPROVEMENTS	32-S2.5	44,204,208	3.12	1,379,171.00	21,077,212	286,863	1,666,034	3.77
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	30-L4	23,598,623	3.33	785,834.00	6,113,571	80,344	866,178	3.67
343.00	PRIME MOVERS	23-R3	63,307,023	4.24	2,686,736.00	29,859,671	281,355	2,968,091	4.69
344.00	GENERATORS	28-R4	8,809,453	3.57	314,497.00	3,819,650	17,190	331,687	3.77
345.00	ACCESSORY ELECTRIC EQUIPMENT	24-L3	25,029,490	4.17	1,043,730.00	10,595,295	0	1,043,730	4.17
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	20-R4	2,124,073	4.55	96,654.00	1,403,089	(35,459)	61,185	2.88
	TOTAL DIESEL PLANT		167,072,870	3.77	6,306,622.00	72,888,488	630,282	6,936,904	4.15
TRANSMISSION PLANT									
351.00	CLEARING LAND AND LAND RIGHTS	65-SQ	3,122,365	1.54	48,084.00	1,216,168	11,467	59,551	1.91
352.00	STRUCTURES AND IMPROVEMENTS	40-R4	3,800,562	2.50	95,014.00	1,928,717	7,572	102,586	2.70
353.00	STATION EQUIPMENT	29-R2.5	15,067,391	3.45	519,825.00	7,295,405	0	519,825	3.45
354.00	TOWERS AND FIXTURES	65-R4	15,297,752	1.54	235,585.00	5,865,859	141,877	377,462	2.47
355.00	POLES AND FIXTURES	45-R3	1,769,695	2.22	39,287.00	503,676	6,959	46,246	2.61
356.00	OVERHEAD CONDUCTORS AND DEVICES	60-R4	10,797,272	1.67	180,314.00	3,894,796	46,863	227,177	2.10
357.00	UNDERGROUND CONDUIT	30-R5	12,434	3.33	414.00	6,930	(162)	252	2.03
358.00	UNDERGROUND CONDUCTORS AND DEVICES	30-R5	16,344	3.33	544.00	9,109	(143)	401	2.45
359.00	ROADS AND TRAILS	40-R2	1,009,617	2.50	25,240.00	427,096	(10,886)	14,354	1.42
	TOTAL TRANSMISSION PLANT		50,893,431	2.25	1,144,307.00	21,147,756	203,548	1,347,855	2.65
DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	40-R2	830,476	2.50	20,762.00	212,321	4,706	25,468	3.07
362.00	STATION EQUIPMENT	25-S2.5	1,932,656	4.00	77,306.00	1,013,542	12,676	88,982	4.66
363.00	STORAGE BATTERY EQUIPMENT	15-R4	82,281	6.67	4,154.00	32,710	(29,864)	(25,710)	(41.28)
364.00	POLES, TOWERS AND FIXTURES	50-R2.5	14,594,265	2.00	291,885.00	4,460,533	(34,545)	257,340	1.76
365.00	OVERHEAD CONDUCTORS AND DEVICES	55-R4	4,366,715	1.82	79,474.00	1,798,082	(9,420)	70,054	1.60
366.00	UNDERGROUND CONDUIT	30-R5	129,167	3.33	4,301.00	30,391	851	5,152	3.99
367.00	UNDERGROUND CONDUCTORS AND DEVICES	30-R5	684,020	3.33	22,745.00	146,677	7,408	30,153	4.41
368.00	LINE TRANSFORMERS	50-R5	6,322,987	2.00	126,460.00	1,940,718	(25,301)	101,159	1.60
369.00	SERVICES	55-R4	2,446,029	1.82	44,518.00	798,179	(3,023)	41,495	1.70
370.00	METERS	18-L1	1,921,657	5.56	106,844.00	708,498	25,989	132,833	6.91
371.00	INSTALLATIONS ON CUSTOMER PREMISES	18-L1	10,771	5.56	599.00	5,666	2,286	2,885	26.79
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	48-R4	1,438,519	2.08	29,921.00	188,117	319	30,240	2.10
	TOTAL DISTRIBUTION PLANT		34,739,544	2.33	808,965.00	11,335,434	(47,918)	761,061	2.19

NORTHWEST TERRITORIES POWER CORPORATION
TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, CALCULATED
ANNUAL AND ACCRUED DEPRECIATION AS OF MARCH 31, 2015
PHASED IN NET SALVAGE
LIFE

ACCOUNT	DESCRIPTION (1)	SURVIVOR CURVE (2)	ORIGINAL COST AS OF MARCH 31, 2015 (3)	ANNUAL RATE (4)	CALCULATED DEPRECIATION ANNUAL AMOUNT (5)	CALCULATED ACCRUED (6)	ANNUAL PROVISION FOR TRUE-UP (7)	TOTAL DEPRECIATION EXPENSE (8)=(5)+(7)	TOTAL DEPRECIATION RATE (10)=(8)/(3)
GENERAL PLANT									
390.01	STRUCTURES AND IMPROVEMENTS								
390.02	HAY RIVER OFFICE BUILDINGS	65-R1.5	4,900,346	1.54	75,465.00	1,200.819	11,994	87,459	1.78
	OTHER SMALL STRUCTURES	25-R1.5	10,554,044	3.97	419,154.00	3,077.313	(258,507)	160,647	1.52
	TOTAL STRUCTURES AND IMPROVEMENTS		15,454,390	3.20	494,619.00	4,278.132	(246,513)	248,106	1.61
382.00	COMPUTER HARDWARE	5-SQ	4,555,365	20.00	911,073.00	3,456,602	481,723	1,392,796	30.57
391.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	619,688	6.67	41,333.00	425,136	(30,289)	11,044	1.78
383.00	COMPUTER SOFTWARE	10-SQ	3,759,264	10.00	375,926.00	2,609,593	44,864	420,790	11.19
391.04	OFFICE FURNITURE & EQUIPMENT - GAINS & LOSSES		-	-	-	-	207,970	207,970	0.00
392.00	TRANSPORTATION EQUIPMENT	7-S1	3,188,608	11.90	379,534.00	2,247,565	0	379,534	11.90
393.00	STORES EQUIPMENT	15-SQ	190,826	6.67	12,728.00	52,491	5,124	17,862	9.35
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	15-SQ	601,668	6.67	40,131.00	288,667	(7,488)	32,643	5.43
395.00	LABORATORY EQUIPMENT	25-SQ	363,344	4.00	14,534.00	279,265	0	14,534	4.00
396.00	POWER OPERATED EQUIPMENT	27-S1.5	4,910,403	3.70	181,685.00	1,639,290	(38,614)	143,071	2.91
397.00	COMMUNICATION EQUIPMENT	20-R3	8,161,399	4.97	405,691.00	2,676,792	(16,941)	388,751	4.76
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	631,377	6.67	42,113.00	444,964	(10,860)	31,253	4.95
399.00	OTHER TANGIBLE PLANT	20-SQ	624,062	5.00	31,203.00	118,073	2,275	33,478	5.36
	TOTAL GENERAL PLANT		43,060,384	6.81	2,930,570.00	18,516,570	391,252	3,321,822	7.71
	TOTAL DEPRECIABLE PLANT		465,097,001	3.00	34,005,762.00	165,556,387	1,288,126	15,293,888	3.28
NONDEPRECIABLE PLANT									
330.00	HYDRO LAND AND LAND RIGHTS		4,108,734						
340.00	DIESEL LAND AND LAND RIGHTS		1,103,813						
350.00	TRANSMISSION LAND AND LAND RIGHTS		5,466						
360.00	DISTRIBUTION LAND AND LAND RIGHTS		338,857						
389.00	GENERAL PLANT LAND AND LAND RIGHTS		337,313						
	FEASIBILITY STUDIES		(5,079,268)						
	TOTAL NONDEPRECIABLE PLANT		814,915						
	TOTAL ELECTRIC PLANT		465,911,916						

NORTHWEST TERRITORIES POWER CORPORATION

TABLE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, CALCULATED ANNUAL AND ACCRUED DEPRECIATION AS OF MARCH 31, 2015
PHASED IN NET SALVAGE
NET SALVAGE

ACCOUNT	DESCRIPTION (1)	SURVIVOR CURVE (2)	PHASED IN SALVAGE PERCENT (3)	RECOMMENDED SALVAGE PERCENT (4)	ORIGINAL COST AT MARCH 31, 2015 (5)	ANNUAL RATE (6)	CALCULATED DEPRECIATION ANNUAL AMOUNT (7)	CALCULATED ACCRUED (8)	ANNUAL PROVISION FOR TRUE-UP (9)	TOTAL DEPRECIATION EXPENSE (10)=(7)+(9)	DEPRECIATION RATE % (11)=(10)/(5)
OTHER UTILITY PROPERTY											
118.00	SOLAR PANELS	25-R3	0	0	1,552,427	0.00	-	-	0	0	0.00
121.00	WIND TURBINES	40-R3	(10)	(15)	353,263	0.25	883	19,672	0	883	0.25
131.00	RESIDUAL HEAT SYSTEM	28-R4	0	0	5,656,681	0.00	-	-	0	0	0.00
	TOTAL OTHER UTILITY PROPERTY				7,562,371	0.01	883	19,672	0	883	0.01
HYDRO PLANT											
331.00	STRUCTURES AND IMPROVEMENTS	100-R3	(5)	(30)	22,598,497	0.05	11,299	1,730,444	0	11,299	0.05
332.00	RESERVOIRS, DAMS AND WATERWAYS	100-R3	(5)	(30)	70,279,438	0.05	35,140	2,963,597	0	35,140	0.05
333.00	WATER WHEELS, TURBINES AND GENERATORS	50-S2	(5)	(15)	32,145,105	0.10	32,145	1,506,214	0	32,145	0.10
334.00	ACCESSORY ELECTRIC EQUIPMENT	40-R2.5	(5)	(20)	22,977,232	0.13	28,721	1,464,187	0	28,721	0.12
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	20-R2	(8)	(10)	3,533,123	0.39	13,729	204,505	0	13,729	0.39
336.00	ROADS, RAILROADS AND BRIDGES	50-R5	(5)	(5)	11,235,007	0.10	11,235	232,325	0	11,235	0.10
	TOTAL HYDRO PLANT				162,768,402	0.08	132,269	8,101,272	-	132,269	0.08
DIESEL PLANT											
341.00	STRUCTURES AND IMPROVEMENTS	32-S2.5	(8)	(35)	44,204,208	0.25	110,334	7,377,028	0	110,334	0.25
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	30-L4	(10)	(75)	23,598,623	0.33	78,584	4,585,177	0	78,584	0.33
343.00	PRIME MOVERS	23-R3	(8)	(25)	63,307,023	0.34	214,939	7,464,921	0	214,939	0.34
344.00	GENERATORS	28-R4	(5)	(5)	8,809,453	0.18	15,725	190,981	0	15,725	0.18
345.00	ACCESSORY ELECTRIC EQUIPMENT	24-L3	(5)	(10)	25,029,490	0.21	52,186	1,059,529	0	52,186	0.21
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	20-R4	0	0	2,124,073	0.00	-	-	0	0	0.00
	TOTAL DIESEL PLANT				167,072,870	0.28	471,768	20,677,636	0	471,768	0.28
TRANSMISSION PLANT											
351.00	CLEARING LAND AND LAND RIGHTS	65-SQ	0	0	3,122,365	0.00	-	-	0	0	0.00
352.00	STRUCTURES AND IMPROVEMENTS	40-R4	0	0	3,800,562	0.00	-	-	0	0	0.00
353.00	STATION EQUIPMENT	29-R2.5	(5)	(20)	15,067,391	0.17	25,991	1,459,078	0	25,991	0.17
354.00	TOWERS AND FIXTURES	65-R4	(5)	(25)	15,297,752	0.08	11,780	1,466,466	0	11,780	0.08
355.00	POLES AND FIXTURES	45-R3	(5)	(25)	1,769,695	0.11	1,965	125,918	0	1,965	0.11
356.00	OVERHEAD CONDUCTORS AND DEVICES	60-R4	(5)	(25)	10,797,272	0.08	9,016	973,699	0	9,016	0.08
357.00	UNDERGROUND CONDUIT	30-R5	0	0	12,434	0.00	-	-	0	0	0.00
358.00	UNDERGROUND CONDUCTORS AND DEVICES	30-R5	0	0	16,344	0.00	-	-	0	0	0.00
359.00	ROADS AND TRAILS	40-R2	0	0	1,009,617	0.00	-	-	0	0	0.00
	TOTAL TRANSMISSION PLANT				50,893,431	0.10	48,752	4,025,161	0	48,752	0.10
DISTRIBUTION PLANT											
361.00	STRUCTURES AND IMPROVEMENTS	40-R2	0	0	830,476	0.00	-	-	0	0	0.00
362.00	STATION EQUIPMENT	25-S2.5	0	0	1,932,656	0.00	-	-	0	0	0.00
363.00	STORAGE BATTERY EQUIPMENT	15-R4	0	0	62,281	0.00	-	-	0	0	0.00
364.00	POLES, TOWERS, AND FIXTURES	50-R2.5	(5)	(25)	14,594,265	0.10	14,595	1,115,137	0	14,595	0.10
365.00	OVERHEAD CONDUCTORS AND DEVICES	55-R4	(5)	(25)	4,366,715	0.09	3,974	449,519	0	3,974	0.09
366.00	UNDERGROUND CONDUIT	30-R5	0	0	129,167	0.00	-	-	0	0	0.00
367.00	UNDERGROUND CONDUCTORS AND DEVICES	30-R5	0	0	684,020	0.00	-	-	0	0	0.00
368.00	LINE TRANSFORMERS	50-R5	0	0	6,322,987	0.00	-	-	0	0	0.00
369.00	SERVICES	55-R4	(5)	(10)	2,446,029	0.09	2,226	79,818	0	2,226	0.09
370.00	METERS	18-L1	0	0	1,921,657	0.00	-	-	0	0	0.00
371.00	INSTALLATIONS ON CUSTOMER PREMISES	18-L1	0	0	10,771	0.00	-	-	0	0	0.00
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	48-R4	(5)	(20)	1,438,519	0.10	1,496	37,622	0	1,496	0.10
	TOTAL DISTRIBUTION PLANT				34,739,544	0.06	22,291	1,682,096	0	22,291	0.06

NORTHWEST TERRITORIES POWER CORPORATION
TABLE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, CALCULATED
ANNUAL AND ACCRUED DEPRECIATION AS OF MARCH 31, 2015
PHASED IN NET SALVAGE
NET SALVAGE

ACCOUNT	DESCRIPTION (1)	SURVIVOR CURVE (2)	PHASED IN SALVAGE PERCENT (3)	RECOMMENDED SALVAGE PERCENT (4)	ORIGINAL COST AT MARCH 31, 2015 (5)	ANNUAL RATE (6)	CALCULATED DEPRECIATION ANNUAL AMOUNT (7)	CALCULATED DEPRECIATION CALCULATED ACCRUED (8)	ANNUAL PROVISION FOR TRUE-UP (9)	TOTAL DEPRECIATION EXPENSE (10)=(7)+(9)	TOTAL DEPRECIATION RATE % (11)=(10)/(5)
GENERAL PLANT											
390.01	STRUCTURES AND IMPROVEMENTS										
	HAY RIVER OFFICE BUILDINGS	65-R1.5	15	15	4,900,346	(0.23)	(11,319)	(180,124)	0	(11,319)	(0.23)
390.02	OTHER SMALL STRUCTURES	25-R1.5	5	5	10,554,044	(0.20)	(20,957)	(153,868)	0	(20,957)	(0.20)
	TOTAL STRUCTURES AND IMPROVEMENTS				15,454,389	(0.21)	-32,276	-333,992	0	(32,276)	(0.21)
382.00	COMPUTER HARDWARE	5-SQ	0	0	4,555,365	0.00	-	-	0	0	0.00
391.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	10	10	619,688	(0.67)	(4,133)	(42,513)	0	(4,133)	(0.67)
383.00	COMPUTER SOFTWARE	10-SQ	0	0	3,759,264	0.00	-	-	0	0	0.00
391.04	OFFICE FURNITURE & EQUIPMENT - GAINS & LOSSES				-	0.00	-	-	0	0	0.00
392.00	TRANSPORTATION EQUIPMENT	7-S1	5	10	3,188,608	(0.59)	(18,977)	(224,755)	0	(18,977)	(0.60)
393.00	STORES EQUIPMENT	15-SQ	0	0	190,826	0.00	-	-	0	0	0.00
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	15-SQ	0	0	601,658	0.00	-	-	0	0	0.00
395.00	LABORATORY EQUIPMENT	25-SQ	0	0	363,344	0.00	-	-	0	0	0.00
396.00	POWER OPERATED EQUIPMENT	27-S1.5	15	15	4,910,403	(0.56)	(27,253)	(245,895)	0	(27,253)	(0.56)
397.00	COMMUNICATION EQUIPMENT	20-R3	10	10	8,161,399	(0.50)	(40,569)	(267,680)	0	(40,569)	(0.50)
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	0	0	631,377	0.00	-	-	0	0	0.00
399.00	OTHER TANGIBLE PLANT	20-SQ	0	0	624,062	0.00	-	-	0	0	0.00
	TOTAL GENERAL PLANT				43,060,384	(0.29)	-123,208	-1,114,835	0	(123,208)	(0.29)
	TOTAL DEPRECIABLE PLANT				466,097,001	0.12	552,755	33,391,002	0	552,755	0.12
NONDEPRECIABLE PLANT											
330.00	HYDRO LAND AND LAND RIGHTS				4,108,734						
340.00	DIESEL LAND AND LAND RIGHTS				1,103,813						
350.00	TRANSMISSION LAND AND LAND RIGHTS				5,466						
360.00	DISTRIBUTION LAND AND LAND RIGHTS				338,857						
389.00	GENERAL PLANT LAND AND LAND RIGHTS				337,313						
	FEASIBILITY STUDIES				(5,079,268)						
	TOTAL NONDEPRECIABLE PLANT				814,915						
	TOTAL ELECTRIC PLANT				466,911,916						

NORTHWEST TERRITORIES POWER CORPORATION
TABLE 2A. CALCULATED ACCRUED DEPRECIATION AND BOOK ACCUMULATED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015
PHASED IN NET SALVAGE
LIFE

ACCOUNT	DESCRIPTION	ORIGINAL COST AT MARCH 31, 2015 (1)	CALCULATED ACCURED DEPRECIATION (2)	BOOK ACCUMULATED DEPRECIATION (3)	ACCUMULATED RESERVE VARIANCE AMOUNT (4)	PERCENT (5)	PROBABLE REMAINING LIFE (6)	ANNUAL PROVISION FOR TRUE-UP (7)=(4)/(6)
OTHER UTILITY PROPERTY								
118.00	HIGH WATER TEMP EQUIPMENT	1,552,427	148,774	38,067	110,707	74.41	22.6	4,899
121.00	WIND TURBINES	353,263	131,149	613,309	(482,160)	(367.64)	25.2	(19,171)
131.00	RESIDUAL HEAT SYSTEM	5,656,681	1,707,454	1,676,500	30,954	1.81	19.6 *	0
	TOTAL OTHER UTILITY PROPERTY	7,562,371	1,987,377	2,327,876	(340,499)			(14,273)
HYDRO PLANT								
331.00	STRUCTURES AND IMPROVEMENTS	22,598,497	5,768,142	6,944,452	(1,176,310)	(20.39)	74.5	(15,794)
332.00	RESERVOIRS, DAMS AND WATERWAYS	70,279,438	9,878,668	5,988,247	3,890,421	39.38	85.9	45,269
333.00	WATER WHEELS, TURBINES AND GENERATORS	32,145,105	10,041,424	6,388,312	3,653,112	36.38	34.4	106,257
334.00	ACCESSORY ELECTRIC EQUIPMENT	22,977,232	7,320,954	9,008,760	(1,687,806)	(23.05)	27.3	(61,915)
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	3,533,123	2,045,025	2,392,349	(347,324)	(16.98)	8.7	(40,060)
336.00	ROADS, RAILROADS, AND BRIDGES	11,235,007	4,646,549	1,964,407	2,682,142	57.72	29.3	91,478
	TOTAL HYDRO PLANT	162,768,402	39,700,762	32,686,528	7,014,234			125,235
DIESEL PLANT								
341.00	STRUCTURES AND IMPROVEMENTS	44,204,208	21,077,212	16,266,527	4,810,685	22.82	16.8	286,863
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	23,598,623	6,113,571	4,325,918	1,787,653	29.24	22.3	80,344
343.00	PRIME MOVERS	63,307,023	29,859,671	26,356,803	3,502,868	11.73	12.5	281,355
344.00	GENERATORS	8,809,453	3,819,650	3,546,851	272,799	7.14	15.9	17,190
345.00	ACCESSORY ELECTRIC EQUIPMENT	25,029,490	10,595,295	10,684,503	(89,208)	(0.84)	13.8 *	0
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	2,124,073	1,403,089	1,667,684	(264,595)	(18.86)	7.5	(35,469)
	TOTAL DIESEL PLANT	167,072,870	72,868,488	62,848,286	10,020,202			630,282
TRANSMISSION PLANT								
351.00	CLEARING LAND AND LAND RIGHTS	3,122,365	1,216,168	761,627	454,541	37.37	39.6	11,467
352.00	STRUCTURES AND IMPROVEMENTS	3,800,562	1,928,717	1,779,552	149,165	7.73	19.7	7,572
353.00	STATION EQUIPMENT	15,067,391	7,295,405	7,103,250	192,155	2.63	15.0 *	0
354.00	TOWERS AND FIXTURES	15,297,752	5,865,859	185,120	5,680,739	96.84	40.0	141,877
355.00	POLES AND FIXTURES	1,769,695	503,676	279,441	224,235	44.52	32.2	6,959
356.00	OVERHEAD CONDUCTORS AND DEVICES	10,797,272	3,894,796	2,100,876	1,793,920	46.06	38.3	46,863
357.00	UNDERGROUND CONDUIT	12,434	6,930	9,078	(2,148)	(31.00)	13.3	(162)
358.00	UNDERGROUND CONDUCTORS AND DEVICES	16,344	9,109	11,008	(1,899)	(20.85)	13.3	(143)
359.00	ROADS AND TRAILS	1,009,617	427,096	678,338	(251,242)	(58.83)	23.1	(10,886)
	TOTAL TRANSMISSION PLANT	50,893,431	21,147,756	12,908,290	8,239,466			203,548
DISTRIBUTION PLANT								
361.00	STRUCTURES AND IMPROVEMENTS	830,476	212,321	72,220	140,101	65.99	29.8	4,706
362.00	STATION EQUIPMENT	1,932,656	1,013,542	862,828	150,714	14.87	11.9	12,676
363.00	STORAGE BATTERY EQUIPMENT	62,281	32,710	245,341	(212,631)	(850.05)	7.1	(29,864)
364.00	POLES, TOWERS, AND FIXTURES	14,594,265	4,460,533	5,659,922	(1,199,389)	(26.89)	34.7	(34,545)
365.00	OVERHEAD CONDUCTORS AND DEVICES	4,366,715	1,798,082	2,102,533	(304,451)	(16.93)	32.3	(9,420)
366.00	UNDERGROUND CONDUIT	129,167	30,391	10,852	19,539	64.29	23.0	851
367.00	UNDERGROUND CONDUCTORS AND DEVICES	684,020	146,677	(28,370)	175,047	119.34	23.6	7,408
368.00	LINE TRANSFORMERS	6,322,987	1,940,718	2,817,408	(876,690)	(45.17)	34.7	(25,301)
369.00	SERVICES	2,446,029	798,179	910,086	(111,907)	(111.907)	37.0	(3,023)
370.00	METERS	1,921,657	708,498	413,525	294,973	41.63	11.4	25,989
371.00	INSTALLATIONS ON CUSTOMER PREMISES	10,771	5,666	(13,811)	19,477	343.76	8.5	2,286
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	1,438,519	188,117	174,789	13,328	7.08	41.8	319
	TOTAL DISTRIBUTION PLANT	34,739,544	11,335,434	13,227,324	(1,891,890)			(47,918)

NORTHWEST TERRITORIES POWER CORPORATION

TABLE 2A. CALCULATED ACCRUED DEPRECIATION AND BOOK ACCUMULATED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015
PHASED IN NET SALVAGE
LIFE

ACCOUNT	DESCRIPTION	ORIGINAL COST AT MARCH 31, 2015 (1)	CALCULATED ACCRUED DEPRECIATION (2)	BOOK ACCUMULATED DEPRECIATION (3)	ACCUMULATED RESERVE VARIANCE AMOUNT (4)	PERCENT (5)	PROBABLE REMAINING LIFE (6)	ANNUAL PROVISION FOR TRUE-UP (7)=(4)/(6)
GENERAL PLANT								
390.01	STRUCTURES AND IMPROVEMENTS							
	HAY RIVER OFFICE BUILDINGS	4,900,346	1,200,819	612,859	587,960	48.96	49.0	11,994
390.02	OTHER SMALL STRUCTURES	10,554,044	3,077,313	7,689,085	(4,611,772)	(149.86)	17.8	(258,507)
	TOTAL STRUCTURES AND IMPROVEMENTS	15,454,389	4,278,132	8,301,944	(4,023,812)			(246,513)
382.00	COMPUTER HARDWARE	4,555,365	3,456,602	1,047,987	2,408,615	69.68	5.0	481,723
391.00	OFFICE FURNITURE	619,688	425,136	576,580	(151,444)	(35.62)	5.0	(30,289)
383.00	COMPUTER SOFTWARE	3,759,264	2,609,593	2,385,271	224,322	8.60	5.0	44,864
391.04	OFFICE FURNITURE & EQUIPMENT - GAINS & LOSSES	0	0	(2,079,703)	2,079,703	0.00	10.0	207,970
392.00	TRANSPORTATION EQUIPMENT	3,188,608	2,247,565	2,167,189	80,376	3.58	5.0 *	0
393.00	STORES EQUIPMENT	190,826	52,491	(3,204)	55,695	106.10	10.9	5,124
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	601,658	288,667	347,073	(58,406)	(20.23)	7.8	(7,488)
395.00	LABORATORY EQUIPMENT	363,344	279,265	288,089	(8,824)	(3.16)	5.8 *	0
396.00	POWER OPERATED EQUIPMENT	4,910,403	1,639,290	2,334,344	(695,054)	(42.40)	18.0	(38,614)
397.00	COMMUNICATION EQUIPMENT	8,161,399	2,676,792	2,905,828	(229,036)	(8.56)	13.5	(16,941)
398.00	MISCELLANEOUS EQUIPMENT	631,377	444,964	499,264	(54,300)	(12.20)	5.0	(10,860)
399.00	OTHER TANGIBLE PLANT	624,062	118,073	80,768	37,305	31.59	16.4	2,275
	TOTAL GENERAL PLANT	43,060,384	18,516,570	18,851,429	(334,859)			391,252
	TOTAL DEPRECIABLE PLANT	466,097,001	165,556,387	142,849,733	22,706,654			1,288,126
NONDEPRECIABLE PLANT								
330.00	HYDRO LAND AND LAND RIGHTS	4,108,734						
340.00	DIESEL LAND AND LAND RIGHTS	1,103,813						
350.00	TRANSMISSION LAND AND LAND RIGHTS	5,466						
360.00	DISTRIBUTION LAND AND LAND RIGHTS	338,857						
389.00	GENERAL PLANT LAND AND LAND RIGHTS	337,313						
	FEASIBILITY STUDIES	(5,079,268)						
	TOTAL NONDEPRECIABLE PLANT	814,915						
	TOTAL ELECTRIC PLANT	466,911,916						

NORTHWEST TERRITORIES POWER CORPORATION
TABLE 2B. CALCULATED ACCRUED DEPRECIATION AND BOOK ACCUMULATED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015
PHASED IN NET SALVAGE
NET SALVAGE

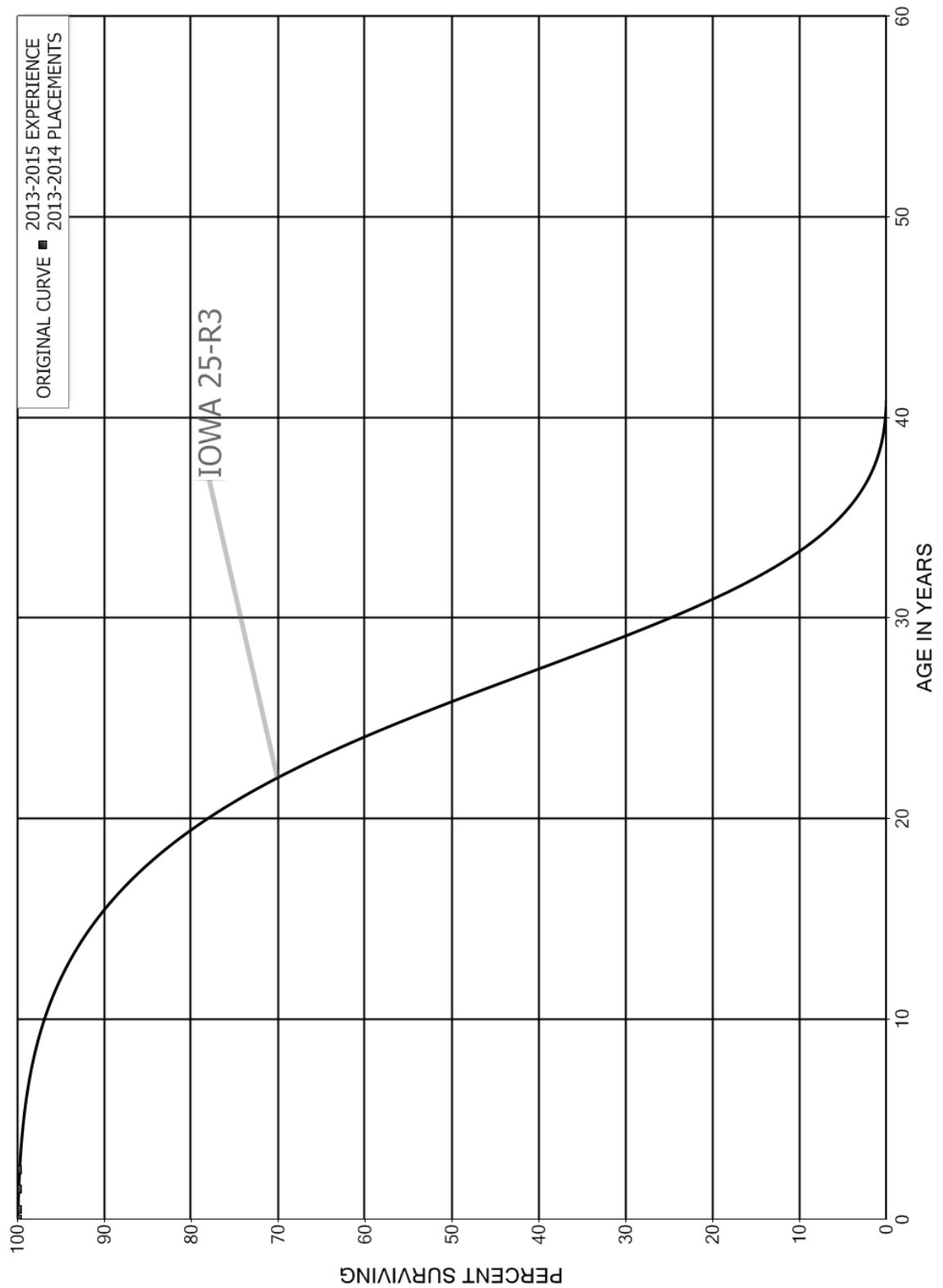
ACCOUNT	DESCRIPTION	ORIGINAL COST AT MARCH 31, 2015 (1)	CALCULATED ACCRUED DEPRECIATION (2)	BOOK ACCUMULATED DEPRECIATION (3)	ACCUMULATED RESERVE VARIANCE AMOUNT (4)	PERCENT (5)	PROBABLE REMAINING LIFE (6)	ANNUAL PROVISION FOR TRUE-UP (7)=(4)/(6)
OTHER UTILITY PROPERTY								
118.00	HIGH WATER TEMP EQUIPMENT	1,552,427	0	0	0	0	22.6	0
121.00	WIND TURBINES	353,263	19,672	(2,080)	21,752	111	25.2	0
131.00	RESIDUAL HEAT SYSTEM	5,656,681	0	0	0	0	19.6	0
	TOTAL OTHER UTILITY PROPERTY	7,562,371	19,672	(2,080)	21,752	0		0
HYDRO PLANT								
331.00	STRUCTURES AND IMPROVEMENTS	22,598,497	1,730,444	2,109,582	(379,138)	(22)	74.5	0
332.00	RESERVOIRS, DAMS AND WATERWAYS	70,279,438	2,963,597	1,295,341	1,668,256	56	85.9	0
333.00	WATER WHEELS, TURBINES AND GENERATORS	32,145,105	1,506,214	346,520	1,159,694	77	34.4	0
334.00	ACCESSORY ELECTRIC EQUIPMENT	22,977,232	1,464,187	540,598	923,589	63	27.3	0
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	3,533,123	204,505	215,798	(11,293)	(6)	8.7	0
336.00	ROADS, RAILROADS, AND BRIDGES	11,235,007	232,325	0	232,325	100	29.3	0
	TOTAL HYDRO PLANT	162,768,402	8,101,272	4,507,839	3,593,433	44		0
DIESEL PLANT								
341.00	STRUCTURES AND IMPROVEMENTS	44,204,208	7,377,028	771,665	6,605,363	90	16.8	0
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	23,598,623	4,585,177	(888,939)	5,474,116	119	22.3	0
343.00	PRIME MOVERS	63,307,023	7,464,921	11,716,685	(4,251,764)	(57)	12.5	0
344.00	GENERATORS	8,809,453	190,981	(2,165)	193,146	101	15.9	0
345.00	ACCESSORY ELECTRIC EQUIPMENT	25,029,490	1,059,529	(95,681)	1,155,210	109	13.8	0
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	2,124,073	0	(18,677)	18,677	0	7.5	0
	TOTAL DIESEL PLANT	167,072,870	20,677,636	11,482,888	9,194,748	44		0
TRANSMISSION PLANT								
351.00	CLEARING LAND AND LAND RIGHTS	3,122,365	0	(5,986)	5,986	0	39.6	0
352.00	STRUCTURES AND IMPROVEMENTS	3,800,562	0	218,672	(218,672)	0	19.7	0
353.00	STATION EQUIPMENT	15,067,391	1,459,078	(58,654)	1,517,732	104	15.0	0
354.00	TOWERS AND FIXTURES	15,297,752	1,466,466	9,033,106	(7,566,640)	(516)	40.0	0
355.00	POLES AND FIXTURES	1,769,695	125,918	502,278	(376,360)	(299)	32.2	0
356.00	OVERHEAD CONDUCTORS AND DEVICES	10,797,272	973,699	6,357,870	(5,384,171)	(553)	38.3	0
357.00	UNDERGROUND CONDUIT	12,434	0	(475)	475	0	13.3	0
358.00	UNDERGROUND CONDUCTORS AND DEVICES	16,344	0	552	(552)	0	13.3	0
359.00	ROADS AND TRAILS	1,009,617	0	0	0	0	23.1	0
	TOTAL TRANSMISSION PLANT	50,893,431	4,025,161	16,047,363	(12,022,202)	(299)		0
DISTRIBUTION PLANT								
361.00	STRUCTURES AND IMPROVEMENTS	830,476	0	11,269	(11,269)	0	29.8	0
362.00	STATION EQUIPMENT	1,932,656	0	0	0	0	11.9	0
363.00	STORAGE BATTERY EQUIPMENT	62,281	0	0	0	0	7.1	0
364.00	POLES, TOWERS, AND FIXTURES	14,594,265	1,115,137	5,435,105	(4,319,968)	(387)	34.7	0
365.00	OVERHEAD CONDUCTORS AND DEVICES	4,366,715	449,519	2,027,028	(1,577,509)	(351)	32.3	0
366.00	UNDERGROUND CONDUIT	129,167	0	0	0	0	23.0	0
367.00	UNDERGROUND CONDUCTORS AND DEVICES	684,020	0	0	0	0	23.6	0
368.00	LINE TRANSFORMERS	6,322,987	0	(106,366)	106,366	0	34.7	0
369.00	SERVICES	2,446,029	79,818	472,054	(392,236)	(491)	37.0	0
370.00	METERS	1,921,657	0	0	0	0	11.4	0
371.00	INSTALLATIONS ON CUSTOMER PREMISES	10,771	0	0	0	0	8.5	0
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	1,438,519	37,622	59,415	(21,793)	(58)	41.8	0
	TOTAL DISTRIBUTION PLANT	34,739,544	1,682,096	7,898,505	(6,216,409)	(370)		0

NORTHWEST TERRITORIES POWER CORPORATION
TABLE 2B. CALCULATED ACCRUED DEPRECIATION AND BOOK ACCUMULATED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015
PHASED IN NET SALVAGE

ACCOUNT	DESCRIPTION	ORIGINAL COST AT MARCH 31, 2015 (1)	CALCULATED ACCRUED DEPRECIATION (2)	BOOK ACCUMULATED DEPRECIATION (3)	ACCUMULATED RESERVE VARIANCE AMOUNT (4)	PERCENT (5)	PROBABLE REMAINING LIFE (6)	ANNUAL PROVISION FOR TRUE-UP (7)=(4)/(6)
GENERAL PLANT								
330.01	STRUCTURES AND IMPROVEMENTS							
330.02	HAY RIVER OFFICE BUILDINGS	4,900,346	(180,124)	188,169	(368,293)	204	49.0	0
	OTHER SMALL STRUCTURES	10,554,044	(153,868)	405,267	(559,135)	363	17.8	0
	TOTAL STRUCTURES AND IMPROVEMENTS	15,454,389	(333,992)	593,436	(927,428)	278		0
382.00	COMPUTER HARDWARE	4,555,365	0	(1,777)	1,777	0	5.0	0
391.00	OFFICE FURNITURE	619,688	(42,513)	(228,141)	185,628	(437)	5.0	0
383.00	COMPUTER SOFTWARE	3,759,264	0	(200)	200	0	5.0	0
391.04	OFFICE FURNITURE & EQUIPMENT - GAINS & LOSSES	0	0	0	0	0	10.0	0
392.00	TRANSPORTATION EQUIPMENT	3,188,608	(224,755)	(566,630)	341,875	(152)	5.0	0
393.00	STORES EQUIPMENT	190,826	0	0	0	0	10.9	0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	601,658	0	0	0	0	7.8	0
395.00	LABORATORY EQUIPMENT	363,344	0	0	0	0	5.8	0
396.00	POWER OPERATED EQUIPMENT	4,910,403	(245,895)	0	(245,895)	100	18.0	0
397.00	COMMUNICATION EQUIPMENT	8,161,399	(267,680)	(10,714)	(256,966)	0	13.5	0
398.00	MISCELLANEOUS EQUIPMENT	631,377	0	0	0	0	5.0	0
399.00	OTHER TANGIBLE PLANT	624,062	0	0	0	0	16.4	0
	TOTAL GENERAL PLANT	43,060,384	(1,114,835)	(214,026)	(900,809)	81		0
	TOTAL DEPRECIABLE PLANT	466,097,001	33,391,002	39,720,489	(6,329,487)			0
NONDEPRECIABLE PLANT								
330.00	HYDRO LAND AND LAND RIGHTS	4,108,734						
340.00	DIESEL LAND AND LAND RIGHTS	1,103,813						
350.00	TRANSMISSION LAND AND LAND RIGHTS	5,466						
360.00	DISTRIBUTION LAND AND LAND RIGHTS	338,857						
389.00	GENERAL PLANT LAND AND LAND RIGHTS	337,313						
	FEASIBILITY STUDIES	(5,079,268)						
	TOTAL NONDEPRECIABLE PLANT	814,915						
	TOTAL ELECTRIC PLANT	466,911,916						

PART V. SERVICE LIFE STATISTICS

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 118.00 - SOLAR PANELS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 118.00 - SOLAR PANELS

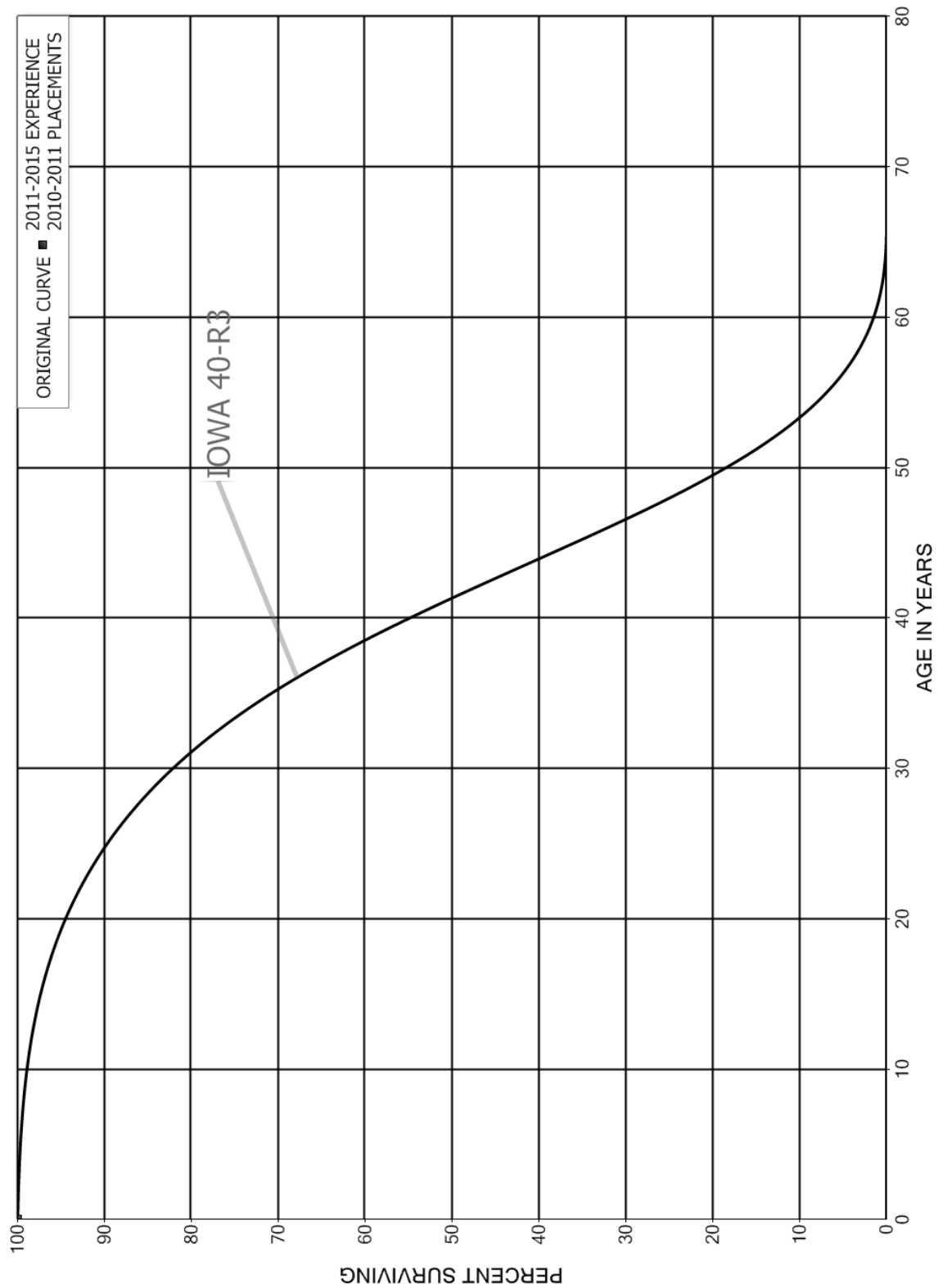
ORIGINAL LIFE TABLE

PLACEMENT BAND 2013-2014

EXPERIENCE BAND 2013-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	799,330		0.0000	1.0000	100.00
0.5	799,330		0.0000	1.0000	100.00
1.5	331,205		0.0000	1.0000	100.00
2.5					100.00

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 121.00 - WIND TURBINES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 121.00 - WIND TURBINES

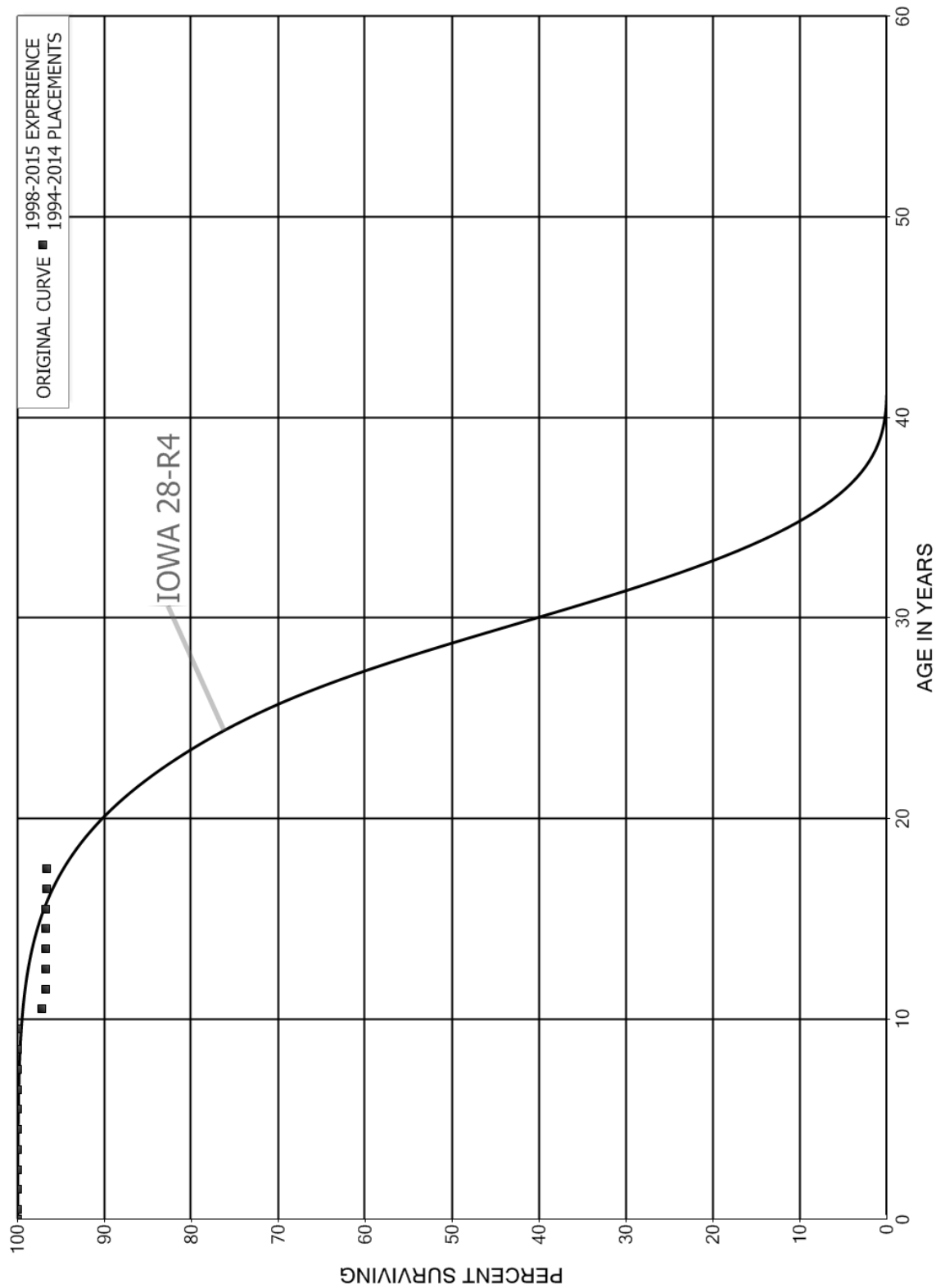
ORIGINAL LIFE TABLE

PLACEMENT BAND 2010-2011

EXPERIENCE BAND 2011-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0					100.00
0.5	404,904		0.0000		
1.5	404,904		0.0000		
2.5	404,904	394,904	0.9753		
3.5	10,000		0.0000		
4.5	10,000		0.0000		
5.5					

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 131.00 - RESIDUAL HEAT SYSTEM
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

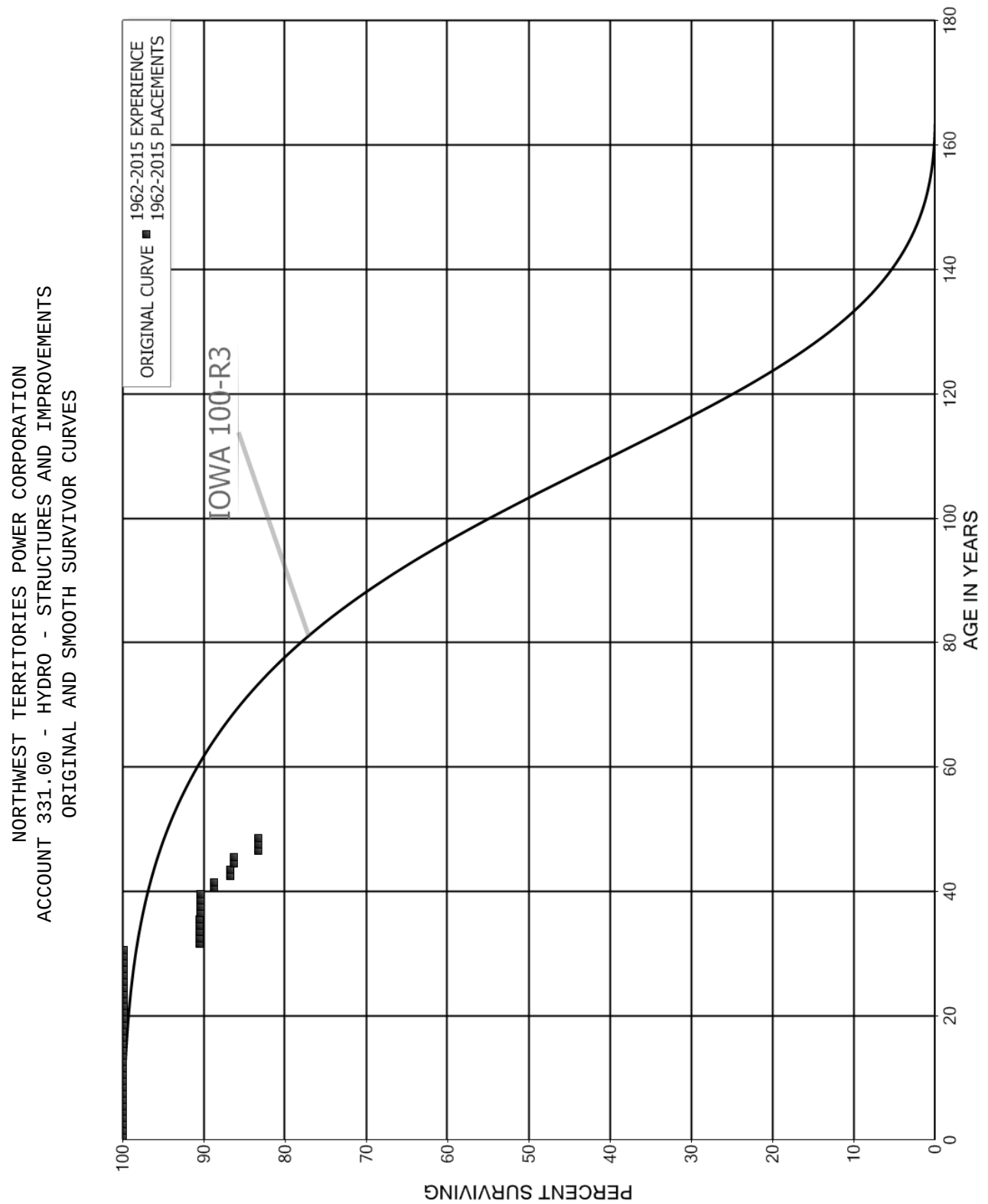
ACCOUNT 131.00 - RESIDUAL HEAT SYSTEM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2014

EXPERIENCE BAND 1998-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,224,853		0.0000	1.0000	100.00
0.5	7,224,853		0.0000	1.0000	100.00
1.5	6,508,929		0.0000	1.0000	100.00
2.5	6,508,929		0.0000	1.0000	100.00
3.5	6,562,442		0.0000	1.0000	100.00
4.5	4,301,695		0.0000	1.0000	100.00
5.5	4,301,695		0.0000	1.0000	100.00
6.5	4,301,695		0.0000	1.0000	100.00
7.5	4,301,695		0.0000	1.0000	100.00
8.5	4,275,778		0.0000	1.0000	100.00
9.5	4,275,778	119,564	0.0280	0.9720	100.00
10.5	3,878,562	17,347	0.0045	0.9955	97.20
11.5	3,861,215		0.0000	1.0000	96.77
12.5	3,861,215		0.0000	1.0000	96.77
13.5	3,749,396		0.0000	1.0000	96.77
14.5	3,749,396		0.0000	1.0000	96.77
15.5	1,577,875	2,000	0.0013	0.9987	96.77
16.5	741,808		0.0000	1.0000	96.65
17.5	36,166		0.0000	1.0000	96.65
18.5	36,166		0.0000	1.0000	96.65
19.5	36,166		0.0000	1.0000	96.65
20.5	36,166		0.0000	1.0000	96.65
21.5					96.65



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 331.00 - HYDRO - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,958,011		0.0000	1.0000	100.00
0.5	25,955,014		0.0000	1.0000	100.00
1.5	25,781,171		0.0000	1.0000	100.00
2.5	24,344,233		0.0000	1.0000	100.00
3.5	24,344,233		0.0000	1.0000	100.00
4.5	24,302,797		0.0000	1.0000	100.00
5.5	24,256,891		0.0000	1.0000	100.00
6.5	23,421,545		0.0000	1.0000	100.00
7.5	23,151,337		0.0000	1.0000	100.00
8.5	22,901,982		0.0000	1.0000	100.00
9.5	22,601,691		0.0000	1.0000	100.00
10.5	21,269,872		0.0000	1.0000	100.00
11.5	21,269,872		0.0000	1.0000	100.00
12.5	21,097,156		0.0000	1.0000	100.00
13.5	21,090,533		0.0000	1.0000	100.00
14.5	21,090,533		0.0000	1.0000	100.00
15.5	20,980,762	4,290	0.0002	0.9998	100.00
16.5	20,973,039		0.0000	1.0000	99.98
17.5	20,029,941	18,062	0.0009	0.9991	99.98
18.5	13,174,738		0.0000	1.0000	99.89
19.5	13,011,495		0.0000	1.0000	99.89
20.5	12,998,543		0.0000	1.0000	99.89
21.5	12,998,543		0.0000	1.0000	99.89
22.5	12,998,543		0.0000	1.0000	99.89
23.5	12,998,543		0.0000	1.0000	99.89
24.5	12,998,543		0.0000	1.0000	99.89
25.5	12,998,543		0.0000	1.0000	99.89
26.5	12,998,543		0.0000	1.0000	99.89
27.5	12,998,543		0.0000	1.0000	99.89
28.5	12,998,543		0.0000	1.0000	99.89
29.5	12,998,543		0.0000	1.0000	99.89
30.5	12,998,543	1,226,186	0.0943	0.9057	99.89
31.5	11,772,357		0.0000	1.0000	90.47
32.5	11,772,357		0.0000	1.0000	90.47
33.5	11,772,357		0.0000	1.0000	90.47
34.5	11,772,357		0.0000	1.0000	90.47
35.5	11,772,357	6,674	0.0006	0.9994	90.47
36.5	11,765,684		0.0000	1.0000	90.42
37.5	2,800,397		0.0000	1.0000	90.42
38.5	1,246,388		0.0000	1.0000	90.42

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 331.00 - HYDRO - STRUCTURES AND IMPROVEMENTS

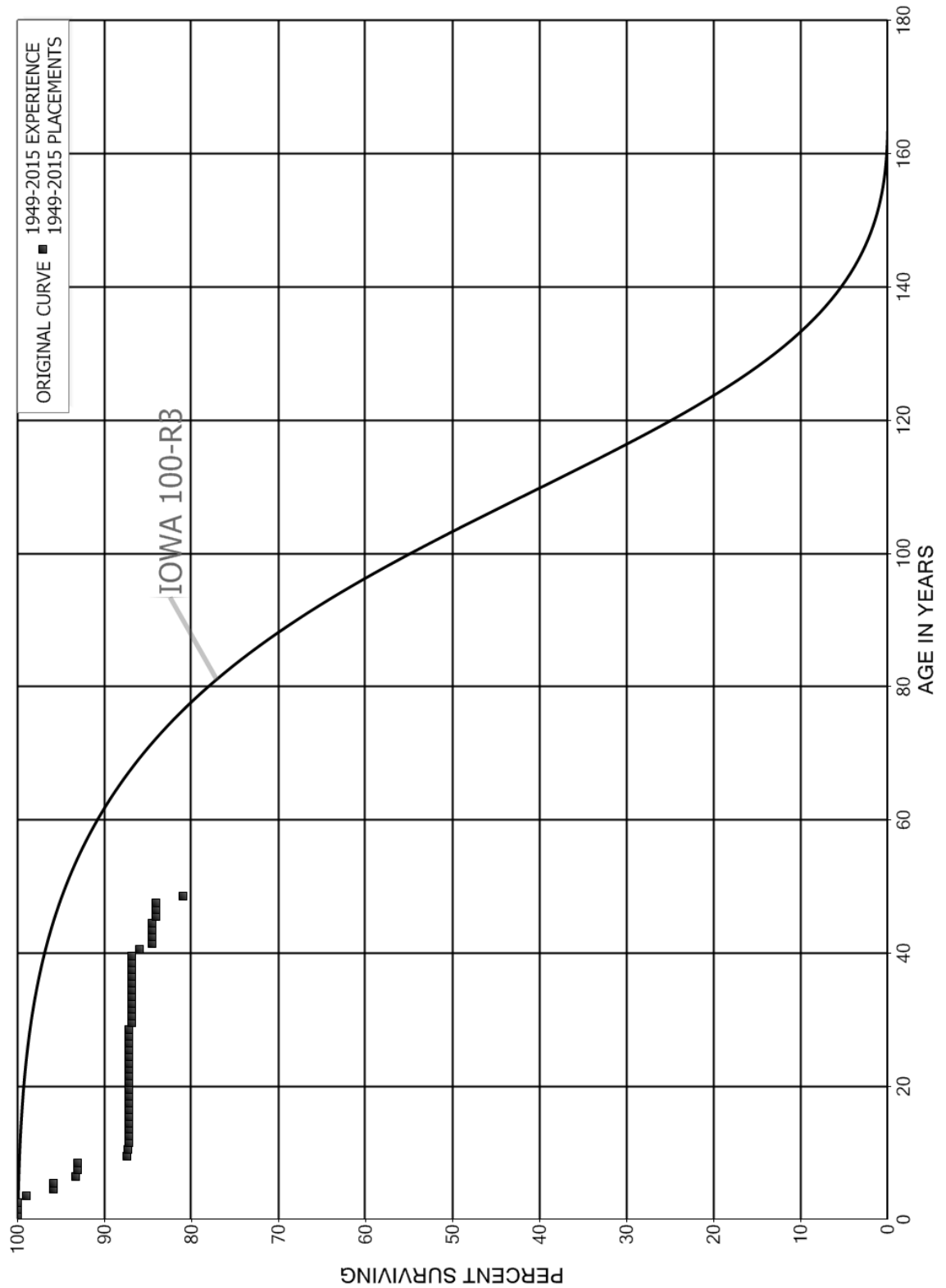
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,246,388	23,912	0.0192	0.9808	90.42
40.5	1,222,477		0.0000	1.0000	88.68
41.5	1,222,477	26,462	0.0216	0.9784	88.68
42.5	1,196,015		0.0000	1.0000	86.76
43.5	1,196,015	6,355	0.0053	0.9947	86.76
44.5	1,189,659		0.0000	1.0000	86.30
45.5	1,189,659	41,527	0.0349	0.9651	86.30
46.5	1,148,133		0.0000	1.0000	83.29
47.5	1,148,133		0.0000	1.0000	83.29
48.5	29,128		0.0000	1.0000	83.29
49.5	29,128		0.0000	1.0000	83.29
50.5	29,128	26,169	0.8984	0.1016	83.29
51.5	2,960	2,960	1.0000		8.46
52.5					

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 332.00 - HYDRO - RESERVOIRS, DAMS AND WATERWAYS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 332.00 - HYDRO - RESERVOIRS, DAMS AND WATERWAYS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2015

EXPERIENCE BAND 1949-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	74,410,315		0.0000	1.0000	100.00
0.5	74,198,105		0.0000	1.0000	100.00
1.5	73,323,167		0.0000	1.0000	100.00
2.5	40,447,369	422,200	0.0104	0.9896	100.00
3.5	39,919,879	1,246,189	0.0312	0.9688	98.96
4.5	38,484,421	500	0.0000	1.0000	95.87
5.5	36,211,418	968,448	0.0267	0.9733	95.87
6.5	34,110,665	74,332	0.0022	0.9978	93.30
7.5	33,918,647		0.0000	1.0000	93.10
8.5	26,981,400	1,651,571	0.0612	0.9388	93.10
9.5	25,075,497	19,001	0.0008	0.9992	87.40
10.5	20,834,652	49,536	0.0024	0.9976	87.33
11.5	20,558,294		0.0000	1.0000	87.13
12.5	20,310,310		0.0000	1.0000	87.13
13.5	19,328,194		0.0000	1.0000	87.13
14.5	19,324,487		0.0000	1.0000	87.13
15.5	19,314,951		0.0000	1.0000	87.13
16.5	19,025,949		0.0000	1.0000	87.13
17.5	18,900,453		0.0000	1.0000	87.13
18.5	12,635,715		0.0000	1.0000	87.13
19.5	12,627,510		0.0000	1.0000	87.13
20.5	12,542,791		0.0000	1.0000	87.13
21.5	12,542,791		0.0000	1.0000	87.13
22.5	12,542,791		0.0000	1.0000	87.13
23.5	12,542,791		0.0000	1.0000	87.13
24.5	12,542,791		0.0000	1.0000	87.13
25.5	12,542,791		0.0000	1.0000	87.13
26.5	12,542,791		0.0000	1.0000	87.13
27.5	12,542,791		0.0000	1.0000	87.13
28.5	12,542,791	47,955	0.0038	0.9962	87.13
29.5	12,494,836		0.0000	1.0000	86.79
30.5	12,494,836		0.0000	1.0000	86.79
31.5	12,494,836		0.0000	1.0000	86.79
32.5	12,494,836		0.0000	1.0000	86.79
33.5	12,494,836		0.0000	1.0000	86.79
34.5	12,494,836		0.0000	1.0000	86.79
35.5	12,494,836		0.0000	1.0000	86.79
36.5	12,494,836		0.0000	1.0000	86.79
37.5	1,066,920		0.0000	1.0000	86.79
38.5	1,066,920		0.0000	1.0000	86.79

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 332.00 - HYDRO - RESERVOIRS, DAMS AND WATERWAYS

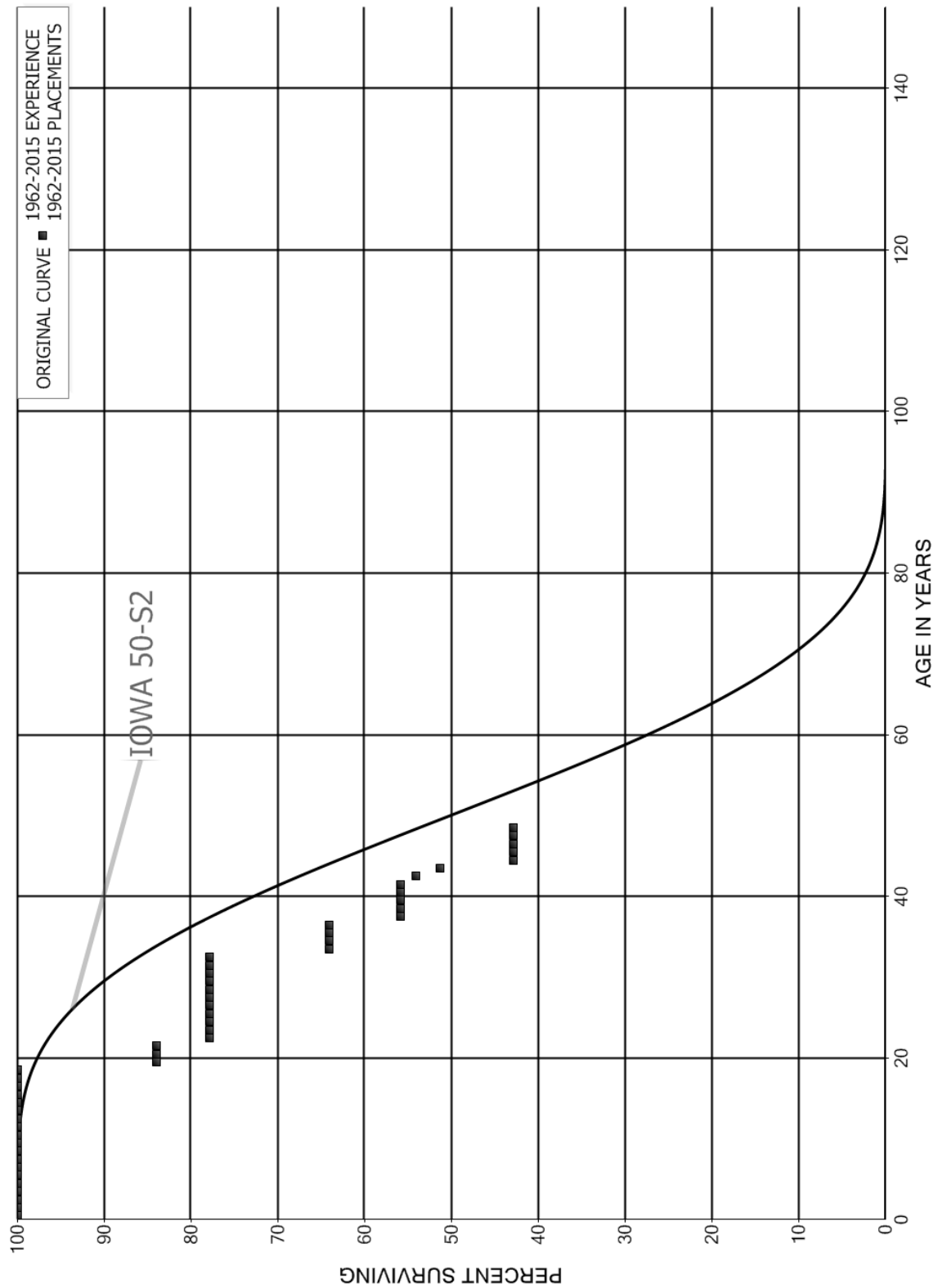
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2015

EXPERIENCE BAND 1949-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,066,920	10,184	0.0095	0.9905	86.79
40.5	1,056,735	18,480	0.0175	0.9825	85.96
41.5	1,038,255		0.0000	1.0000	84.46
42.5	1,038,255		0.0000	1.0000	84.46
43.5	1,038,255		0.0000	1.0000	84.46
44.5	1,038,255	5,265	0.0051	0.9949	84.46
45.5	1,032,990		0.0000	1.0000	84.03
46.5	1,032,990		0.0000	1.0000	84.03
47.5	1,032,990	37,978	0.0368	0.9632	84.03
48.5	202,748	200	0.0010	0.9990	80.94
49.5	202,548		0.0000	1.0000	80.86
50.5	202,548		0.0000	1.0000	80.86
51.5	202,548		0.0000	1.0000	80.86
52.5	202,548		0.0000	1.0000	80.86
53.5	202,548	18,004	0.0889	0.9111	80.86
54.5	184,545		0.0000	1.0000	73.68
55.5	184,545		0.0000	1.0000	73.68
56.5	184,545		0.0000	1.0000	73.68
57.5	184,545		0.0000	1.0000	73.68
58.5	184,545	25,675	0.1391	0.8609	73.68
59.5	158,870		0.0000	1.0000	63.43
60.5	158,870	50,000	0.3147	0.6853	63.43
61.5	108,870	108,870	1.0000		43.46
62.5					

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 333.00 - HYDRO - WATER WHEELS, TURBINES AND GENERATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 333.00 - HYDRO - WATER WHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,299,423		0.0000	1.0000	100.00
0.5	22,016,431		0.0000	1.0000	100.00
1.5	20,654,135		0.0000	1.0000	100.00
2.5	20,654,135		0.0000	1.0000	100.00
3.5	20,405,608		0.0000	1.0000	100.00
4.5	20,405,608		0.0000	1.0000	100.00
5.5	20,405,608		0.0000	1.0000	100.00
6.5	20,074,032		0.0000	1.0000	100.00
7.5	19,439,224		0.0000	1.0000	100.00
8.5	19,193,004		0.0000	1.0000	100.00
9.5	19,185,142		0.0000	1.0000	100.00
10.5	16,562,684		0.0000	1.0000	100.00
11.5	16,558,765		0.0000	1.0000	100.00
12.5	16,552,418		0.0000	1.0000	100.00
13.5	16,475,293		0.0000	1.0000	100.00
14.5	16,448,267		0.0000	1.0000	100.00
15.5	16,412,869		0.0000	1.0000	100.00
16.5	16,383,794		0.0000	1.0000	100.00
17.5	15,423,686		0.0000	1.0000	100.00
18.5	2,877,273	462,196	0.1606	0.8394	100.00
19.5	1,964,726		0.0000	1.0000	83.94
20.5	1,964,726		0.0000	1.0000	83.94
21.5	1,964,726	141,970	0.0723	0.9277	83.94
22.5	1,822,756		0.0000	1.0000	77.87
23.5	1,822,756		0.0000	1.0000	77.87
24.5	1,822,756		0.0000	1.0000	77.87
25.5	1,822,756		0.0000	1.0000	77.87
26.5	1,822,756		0.0000	1.0000	77.87
27.5	1,822,756		0.0000	1.0000	77.87
28.5	1,822,756		0.0000	1.0000	77.87
29.5	1,704,218		0.0000	1.0000	77.87
30.5	1,704,218		0.0000	1.0000	77.87
31.5	1,704,218		0.0000	1.0000	77.87
32.5	1,704,218	301,856	0.1771	0.8229	77.87
33.5	1,402,362		0.0000	1.0000	64.08
34.5	1,402,362		0.0000	1.0000	64.08
35.5	1,402,362		0.0000	1.0000	64.08
36.5	1,402,362	181,401	0.1294	0.8706	64.08
37.5	1,220,961		0.0000	1.0000	55.79
38.5	1,220,961		0.0000	1.0000	55.79

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 333.00 - HYDRO - WATER WHEELS, TURBINES AND GENERATORS

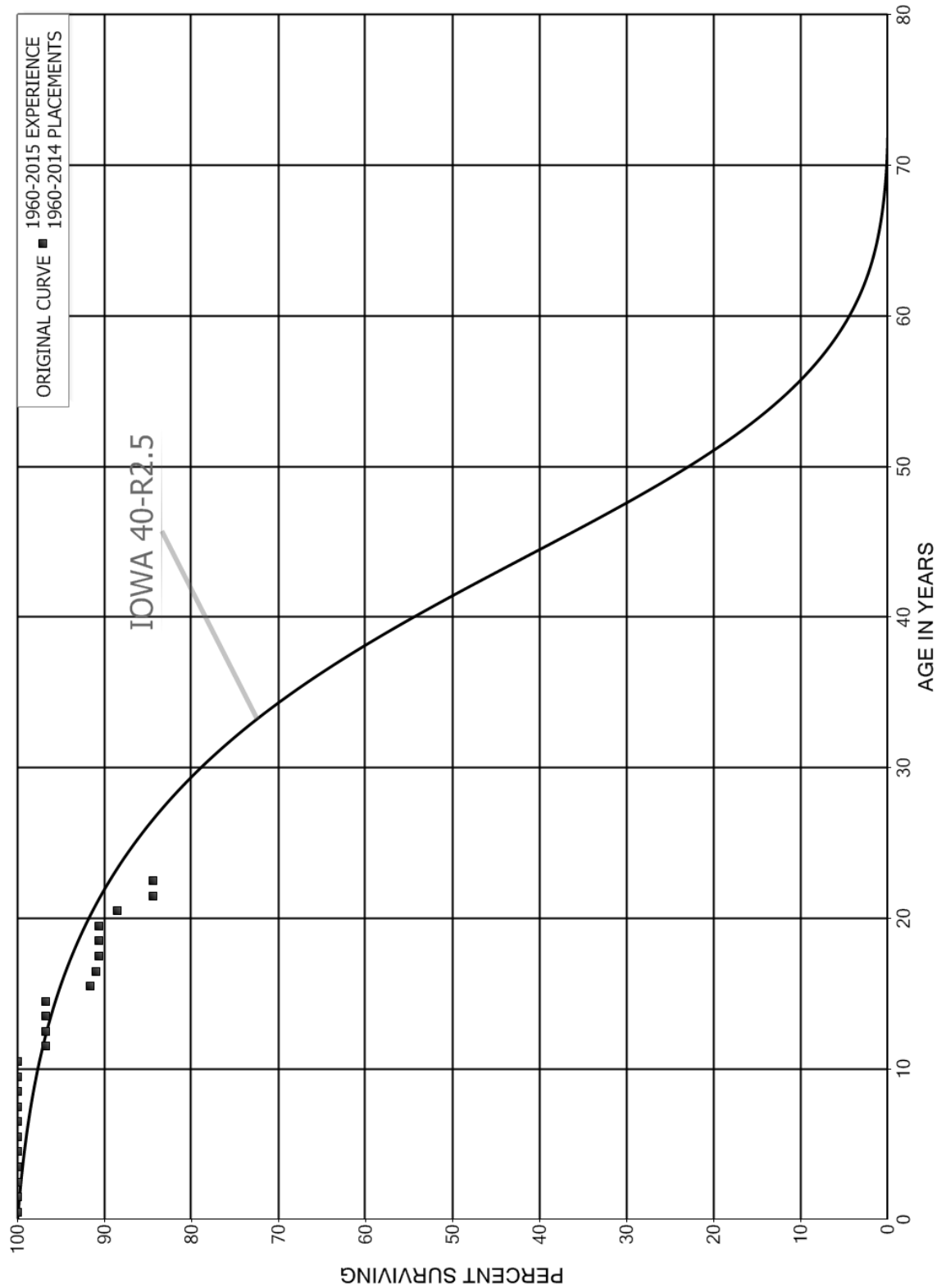
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,220,961		0.0000	1.0000	55.79
40.5	1,220,961		0.0000	1.0000	55.79
41.5	1,220,961	38,725	0.0317	0.9683	55.79
42.5	1,182,236	60,745	0.0514	0.9486	54.02
43.5	1,121,490	184,231	0.1643	0.8357	51.24
44.5	937,259		0.0000	1.0000	42.83
45.5	937,259		0.0000	1.0000	42.83
46.5	937,259		0.0000	1.0000	42.83
47.5	937,259		0.0000	1.0000	42.83
48.5					42.83

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 334.00 - HYDRO - ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 334.00 - HYDRO - ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2014

EXPERIENCE BAND 1960-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	18,916,889		0.0000	1.0000	100.00
0.5	18,916,889		0.0000	1.0000	100.00
1.5	17,692,524		0.0000	1.0000	100.00
2.5	16,871,012		0.0000	1.0000	100.00
3.5	15,053,345		0.0000	1.0000	100.00
4.5	14,223,229		0.0000	1.0000	100.00
5.5	13,861,824		0.0000	1.0000	100.00
6.5	8,243,017		0.0000	1.0000	100.00
7.5	7,170,777		0.0000	1.0000	100.00
8.5	7,102,357		0.0000	1.0000	100.00
9.5	7,102,357		0.0000	1.0000	100.00
10.5	5,785,489	186,838	0.0323	0.9677	100.00
11.5	5,598,650		0.0000	1.0000	96.77
12.5	5,471,789		0.0000	1.0000	96.77
13.5	5,471,789		0.0000	1.0000	96.77
14.5	4,326,680	230,289	0.0532	0.9468	96.77
15.5	4,096,390	29,578	0.0072	0.9928	91.62
16.5	3,988,276	14,290	0.0036	0.9964	90.96
17.5	3,858,087		0.0000	1.0000	90.63
18.5	440,338		0.0000	1.0000	90.63
19.5	379,547	9,055	0.0239	0.9761	90.63
20.5	359,457	16,506	0.0459	0.9541	88.47
21.5	342,951		0.0000	1.0000	84.41
22.5	21,326		0.0000	1.0000	84.41
23.5	21,326		0.0000	1.0000	84.41
24.5	21,326		0.0000	1.0000	84.41
25.5	21,326		0.0000	1.0000	84.41
26.5	21,326		0.0000	1.0000	84.41
27.5	21,326	7,149	0.3352	0.6648	84.41
28.5	14,177		0.0000	1.0000	56.11
29.5	14,177		0.0000	1.0000	56.11
30.5	14,177		0.0000	1.0000	56.11
31.5	14,177		0.0000	1.0000	56.11
32.5	14,177		0.0000	1.0000	56.11
33.5	14,177		0.0000	1.0000	56.11
34.5	14,177		0.0000	1.0000	56.11
35.5	14,177		0.0000	1.0000	56.11
36.5	14,177	6,544	0.4616	0.5384	56.11
37.5	7,633		0.0000	1.0000	30.21
38.5	7,633		0.0000	1.0000	30.21

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 334.00 - HYDRO - ACCESSORY ELECTRIC EQUIPMENT

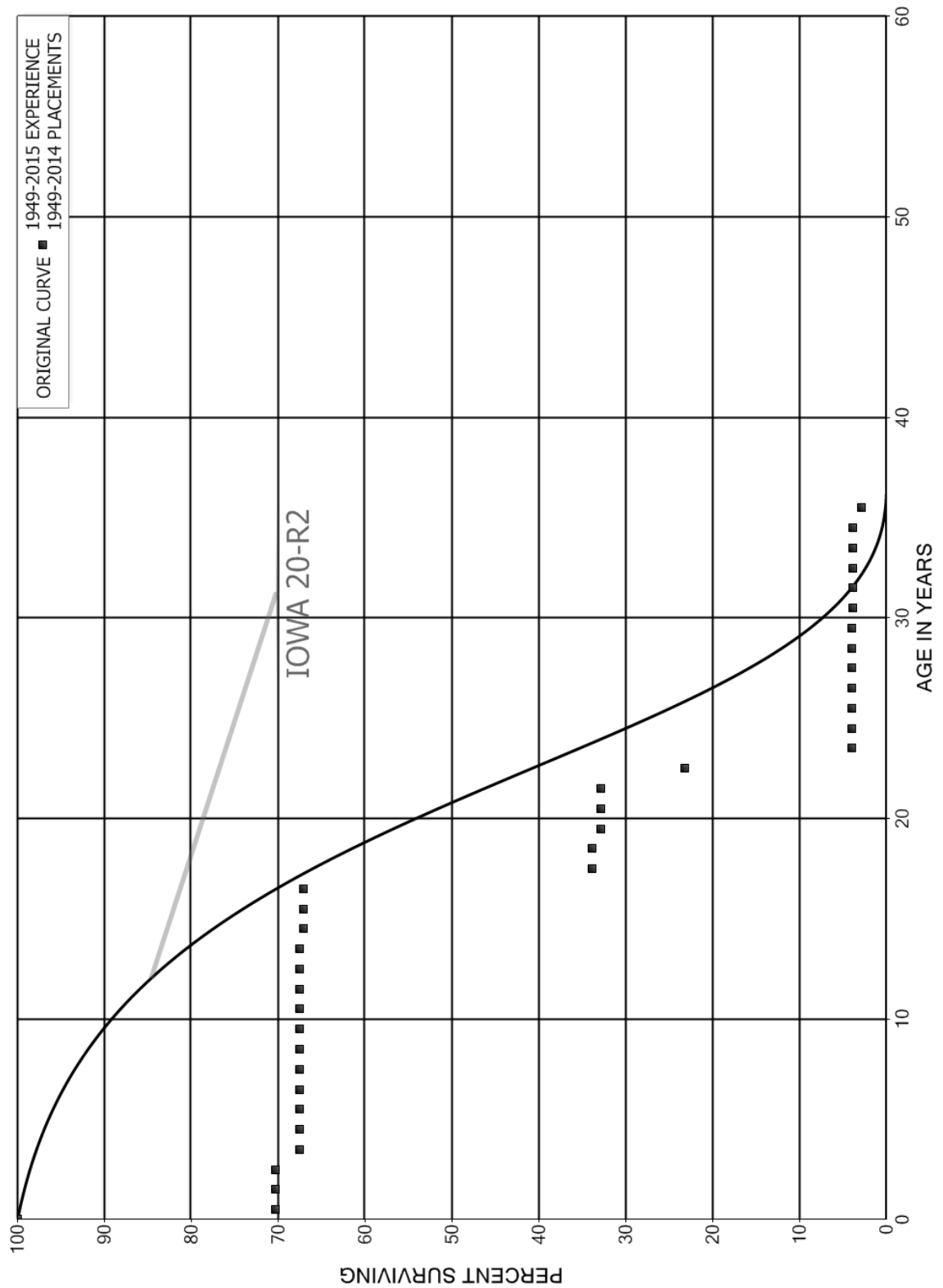
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2014

EXPERIENCE BAND 1960-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,633		0.0000	1.0000	30.21
40.5	7,633		0.0000	1.0000	30.21
41.5	7,633	5,745	0.7526	0.2474	30.21
42.5	1,888	1,852	0.9809	0.0191	7.47
43.5					0.14

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 335.00 - HYDRO - MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 335.00 - HYDRO - MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2014

EXPERIENCE BAND 1949-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,456,932	1,618,826	0.2967	0.7033	100.00
0.5	3,838,105		0.0000	1.0000	70.33
1.5	3,832,854		0.0000	1.0000	70.33
2.5	3,743,752	147,935	0.0395	0.9605	70.33
3.5	3,595,817		0.0000	1.0000	67.56
4.5	3,555,968		0.0000	1.0000	67.56
5.5	2,018,583		0.0000	1.0000	67.56
6.5	1,857,452		0.0000	1.0000	67.56
7.5	1,857,452		0.0000	1.0000	67.56
8.5	1,716,055	1,000	0.0006	0.9994	67.56
9.5	1,668,267		0.0000	1.0000	67.52
10.5	1,416,534		0.0000	1.0000	67.52
11.5	1,416,534		0.0000	1.0000	67.52
12.5	1,401,198		0.0000	1.0000	67.52
13.5	1,370,565	8,713	0.0064	0.9936	67.52
14.5	1,308,111		0.0000	1.0000	67.09
15.5	1,190,019	513	0.0004	0.9996	67.09
16.5	1,189,506	588,840	0.4950	0.5050	67.06
17.5	582,244		0.0000	1.0000	33.86
18.5	579,560	17,507	0.0302	0.9698	33.86
19.5	562,052	556	0.0010	0.9990	32.84
20.5	561,496		0.0000	1.0000	32.81
21.5	561,496	164,798	0.2935	0.7065	32.81
22.5	396,698	329,595	0.8308	0.1692	23.18
23.5	67,103		0.0000	1.0000	3.92
24.5	66,745		0.0000	1.0000	3.92
25.5	66,745		0.0000	1.0000	3.92
26.5	66,745		0.0000	1.0000	3.92
27.5	66,745		0.0000	1.0000	3.92
28.5	66,745		0.0000	1.0000	3.92
29.5	66,745	2,222	0.0333	0.9667	3.92
30.5	64,522		0.0000	1.0000	3.79
31.5	64,522		0.0000	1.0000	3.79
32.5	64,522		0.0000	1.0000	3.79
33.5	64,522		0.0000	1.0000	3.79
34.5	64,522	16,126	0.2499	0.7501	3.79
35.5	48,396		0.0000	1.0000	2.84
36.5	48,396		0.0000	1.0000	2.84
37.5	48,396		0.0000	1.0000	2.84
38.5	48,396		0.0000	1.0000	2.84

NORTHWEST TERRITORIES POWER CORPORATION

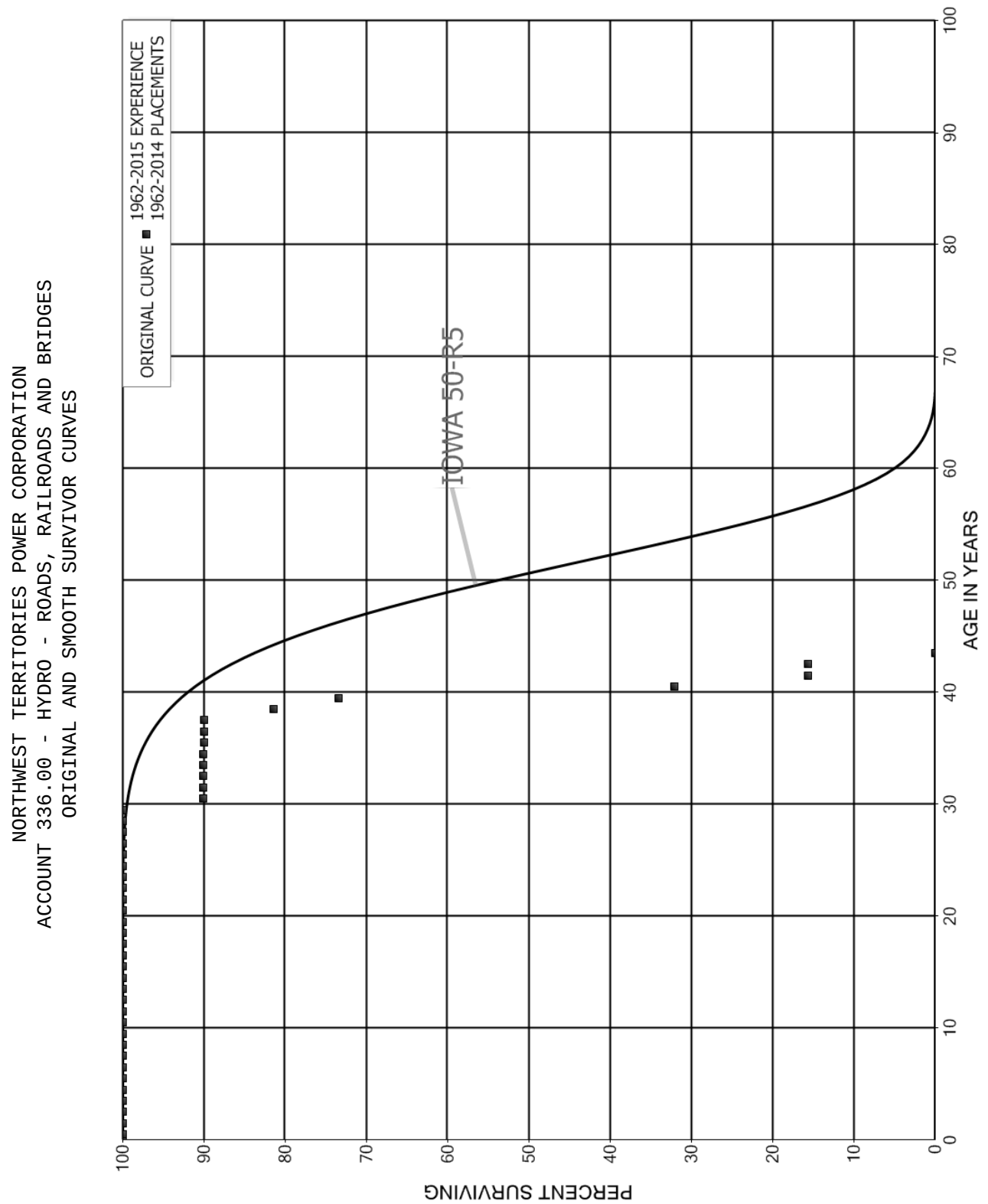
ACCOUNT 335.00 - HYDRO - MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2014

EXPERIENCE BAND 1949-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	48,396		0.0000	1.0000	2.84
40.5	48,396		0.0000	1.0000	2.84
41.5	48,396		0.0000	1.0000	2.84
42.5	48,396		0.0000	1.0000	2.84
43.5	48,396		0.0000	1.0000	2.84
44.5	48,396		0.0000	1.0000	2.84
45.5	48,396		0.0000	1.0000	2.84
46.5	48,396		0.0000	1.0000	2.84
47.5	48,396		0.0000	1.0000	2.84
48.5	48,396		0.0000	1.0000	2.84
49.5	48,396		0.0000	1.0000	2.84
50.5	48,396		0.0000	1.0000	2.84
51.5	48,396		0.0000	1.0000	2.84
52.5	48,396		0.0000	1.0000	2.84
53.5	48,396		0.0000	1.0000	2.84
54.5	48,396	16,458	0.3401	0.6599	2.84
55.5	31,939		0.0000	1.0000	1.88
56.5	31,939		0.0000	1.0000	1.88
57.5	31,939		0.0000	1.0000	1.88
58.5	31,939	31,939	1.0000		1.88
59.5					



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 336.00 - HYDRO - ROADS, RAILROADS AND BRIDGES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2014

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,229,057		0.0000	1.0000	100.00
0.5	11,229,057		0.0000	1.0000	100.00
1.5	11,135,852		0.0000	1.0000	100.00
2.5	10,745,012		0.0000	1.0000	100.00
3.5	10,745,012		0.0000	1.0000	100.00
4.5	10,474,182		0.0000	1.0000	100.00
5.5	10,097,417		0.0000	1.0000	100.00
6.5	9,443,035		0.0000	1.0000	100.00
7.5	8,476,635		0.0000	1.0000	100.00
8.5	7,597,200		0.0000	1.0000	100.00
9.5	7,389,821		0.0000	1.0000	100.00
10.5	6,516,651		0.0000	1.0000	100.00
11.5	6,516,651		0.0000	1.0000	100.00
12.5	6,277,713		0.0000	1.0000	100.00
13.5	5,510,846		0.0000	1.0000	100.00
14.5	5,510,846		0.0000	1.0000	100.00
15.5	5,457,856		0.0000	1.0000	100.00
16.5	5,457,856		0.0000	1.0000	100.00
17.5	5,395,506		0.0000	1.0000	100.00
18.5	4,946,708		0.0000	1.0000	100.00
19.5	4,946,708		0.0000	1.0000	100.00
20.5	4,946,708		0.0000	1.0000	100.00
21.5	4,946,708		0.0000	1.0000	100.00
22.5	4,946,708		0.0000	1.0000	100.00
23.5	4,946,708		0.0000	1.0000	100.00
24.5	4,946,708	3,189	0.0006	0.9994	100.00
25.5	4,943,519		0.0000	1.0000	99.94
26.5	4,943,519		0.0000	1.0000	99.94
27.5	4,943,519		0.0000	1.0000	99.94
28.5	4,943,519		0.0000	1.0000	99.94
29.5	4,943,519	486,842	0.0085	0.9015	99.94
30.5	4,456,677		0.0000	1.0000	90.09
31.5	4,456,677		0.0000	1.0000	90.09
32.5	4,456,677		0.0000	1.0000	90.09
33.5	4,456,677		0.0000	1.0000	90.09
34.5	4,456,677	5,538	0.0012	0.9988	90.09
35.5	4,451,139		0.0000	1.0000	89.98
36.5	4,451,139		0.0000	1.0000	89.98
37.5	243,052	23,332	0.0960	0.9040	89.98
38.5	219,720	21,558	0.0981	0.9019	81.34

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 336.00 - HYDRO - ROADS, RAILROADS AND BRIDGES

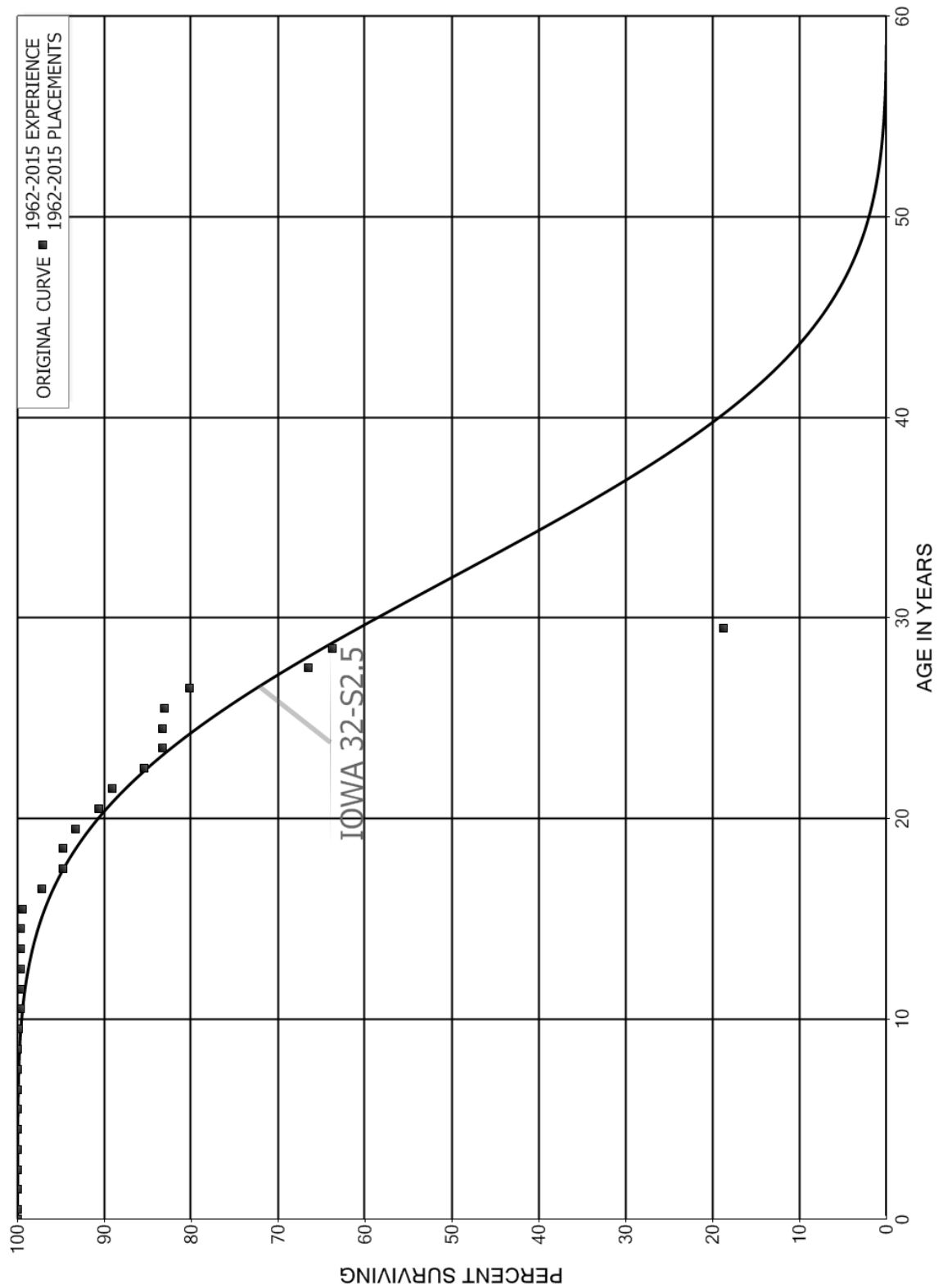
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2014

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	198,162	111,621	0.5633	0.4367	73.36
40.5	86,542	44,322	0.5121	0.4879	32.04
41.5	42,220		0.0000	1.0000	15.63
42.5	42,220	42,220	1.0000		15.63
43.5					

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 341.00 - DIESEL - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 341.00 - DIESEL - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	58,878,522		0.0000	1.0000	100.00
0.5	58,268,988	2,915	0.0001	0.9999	100.00
1.5	54,251,810	2,054	0.0000	1.0000	99.99
2.5	49,584,435		0.0000	1.0000	99.99
3.5	46,463,056	44,174	0.0010	0.9990	99.99
4.5	45,789,992		0.0000	1.0000	99.90
5.5	44,553,686		0.0000	1.0000	99.90
6.5	35,488,139		0.0000	1.0000	99.90
7.5	33,153,779		0.0000	1.0000	99.90
8.5	23,693,044	9,285	0.0004	0.9996	99.90
9.5	22,369,851	49,867	0.0022	0.9978	99.86
10.5	17,138,827		0.0000	1.0000	99.63
11.5	16,989,077		0.0000	1.0000	99.63
12.5	16,859,409		0.0000	1.0000	99.63
13.5	16,432,058	6,338	0.0004	0.9996	99.63
14.5	16,152,093	27,612	0.0017	0.9983	99.60
15.5	11,564,553	261,019	0.0226	0.9774	99.43
16.5	10,105,221	257,908	0.0255	0.9745	97.18
17.5	8,001,714	805	0.0001	0.9999	94.70
18.5	6,458,090	93,529	0.0145	0.9855	94.69
19.5	3,269,683	93,636	0.0286	0.9714	93.32
20.5	2,599,979	43,934	0.0169	0.9831	90.65
21.5	2,556,045	106,458	0.0416	0.9584	89.12
22.5	2,512,928	63,731	0.0254	0.9746	85.40
23.5	2,449,197		0.0000	1.0000	83.24
24.5	2,449,197	6,003	0.0025	0.9975	83.24
25.5	2,443,194	83,174	0.0340	0.9660	83.03
26.5	2,360,020	403,063	0.1708	0.8292	80.21
27.5	1,956,957	81,856	0.0418	0.9582	66.51
28.5	1,875,101	1,323,569	0.7059	0.2941	63.73
29.5	551,532	96,816	0.1755	0.8245	18.74
30.5	454,715	152,870	0.3362	0.6638	15.45
31.5	301,846		0.0000	1.0000	10.26
32.5	301,846	12,550	0.0416	0.9584	10.26
33.5	289,296		0.0000	1.0000	9.83
34.5	289,296	53,779	0.1859	0.8141	9.83
35.5	235,517	36,570	0.1553	0.8447	8.00
36.5	198,947	33,630	0.1690	0.8310	6.76
37.5	165,317	7,689	0.0465	0.9535	5.62
38.5	157,628		0.0000	1.0000	5.36

NORTHWEST TERRITORIES POWER CORPORATION

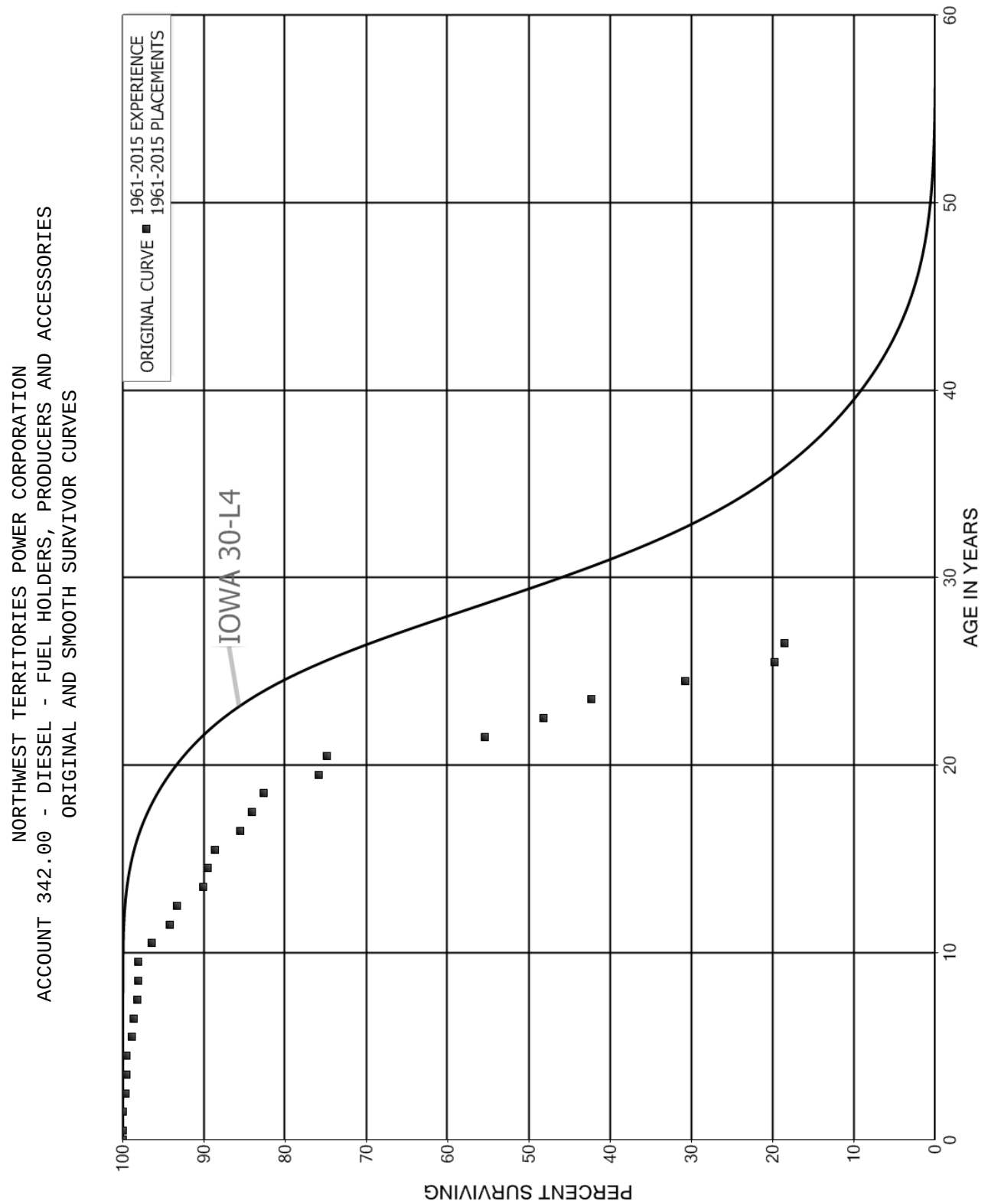
ACCOUNT 341.00 - DIESEL - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	157,628	10,608	0.0673	0.9327	5.36
40.5	127,098	3,239	0.0255	0.9745	5.00
41.5	123,859	11,000	0.0888	0.9112	4.87
42.5	112,859		0.0000	1.0000	4.44
43.5	112,859		0.0000	1.0000	4.44
44.5	112,859		0.0000	1.0000	4.44
45.5	112,859		0.0000	1.0000	4.44
46.5	112,859		0.0000	1.0000	4.44
47.5	112,859		0.0000	1.0000	4.44
48.5	112,859		0.0000	1.0000	4.44
49.5	112,859		0.0000	1.0000	4.44
50.5	112,859		0.0000	1.0000	4.44
51.5	112,859		0.0000	1.0000	4.44
52.5	42,913		0.0000	1.0000	4.44
53.5					4.44



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 342.00 - DIESEL - FUEL HOLDERS, PRODUCERS AND ACCESSORIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1961-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	30,863,002		0.0000	1.0000	100.00
0.5	30,568,495		0.0000	1.0000	100.00
1.5	23,545,784	85,548	0.0036	0.9964	100.00
2.5	18,805,313	22,029	0.0012	0.9988	99.64
3.5	18,783,284		0.0000	1.0000	99.52
4.5	18,384,145	122,537	0.0067	0.9933	99.52
5.5	17,162,279	45,713	0.0027	0.9973	98.86
6.5	15,288,485	67,403	0.0044	0.9956	98.59
7.5	14,654,040	10,204	0.0007	0.9993	98.16
8.5	13,643,091		0.0000	1.0000	98.09
9.5	13,114,402	222,759	0.0170	0.9830	98.09
10.5	12,253,621	283,232	0.0231	0.9769	96.42
11.5	11,970,389	110,751	0.0093	0.9907	94.20
12.5	11,587,439	406,574	0.0351	0.9649	93.32
13.5	10,949,786	65,217	0.0060	0.9940	90.05
14.5	10,530,572	99,547	0.0095	0.9905	89.51
15.5	9,010,725	317,172	0.0352	0.9648	88.67
16.5	8,211,536	141,662	0.0173	0.9827	85.55
17.5	7,802,325	134,836	0.0173	0.9827	84.07
18.5	5,947,240	487,863	0.0820	0.9180	82.62
19.5	3,793,632	51,124	0.0135	0.9865	75.84
20.5	1,734,502	449,270	0.2590	0.7410	74.82
21.5	1,285,231	167,445	0.1303	0.8697	55.44
22.5	1,117,787	138,112	0.1236	0.8764	48.22
23.5	979,675	268,473	0.2740	0.7260	42.26
24.5	635,202	225,893	0.3556	0.6444	30.68
25.5	409,309	25,827	0.0631	0.9369	19.77
26.5	383,482	10,352	0.0270	0.9730	18.52
27.5	245,500	15,000	0.0611	0.9389	18.02
28.5	230,500	962	0.0042	0.9958	16.92
29.5	229,538	46,776	0.2038	0.7962	16.85
30.5	182,762	13,131	0.0718	0.9282	13.42
31.5	169,630		0.0000	1.0000	12.45
32.5	169,630	23,653	0.1394	0.8606	12.45
33.5	145,977		0.0000	1.0000	10.72
34.5	145,977		0.0000	1.0000	10.72
35.5	145,977	35,396	0.2425	0.7575	10.72
36.5	110,581		0.0000	1.0000	8.12
37.5	110,581		0.0000	1.0000	8.12
38.5	110,581	67,843	0.6135	0.3865	8.12

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 342.00 - DIESEL - FUEL HOLDERS, PRODUCERS AND ACCESSORIES

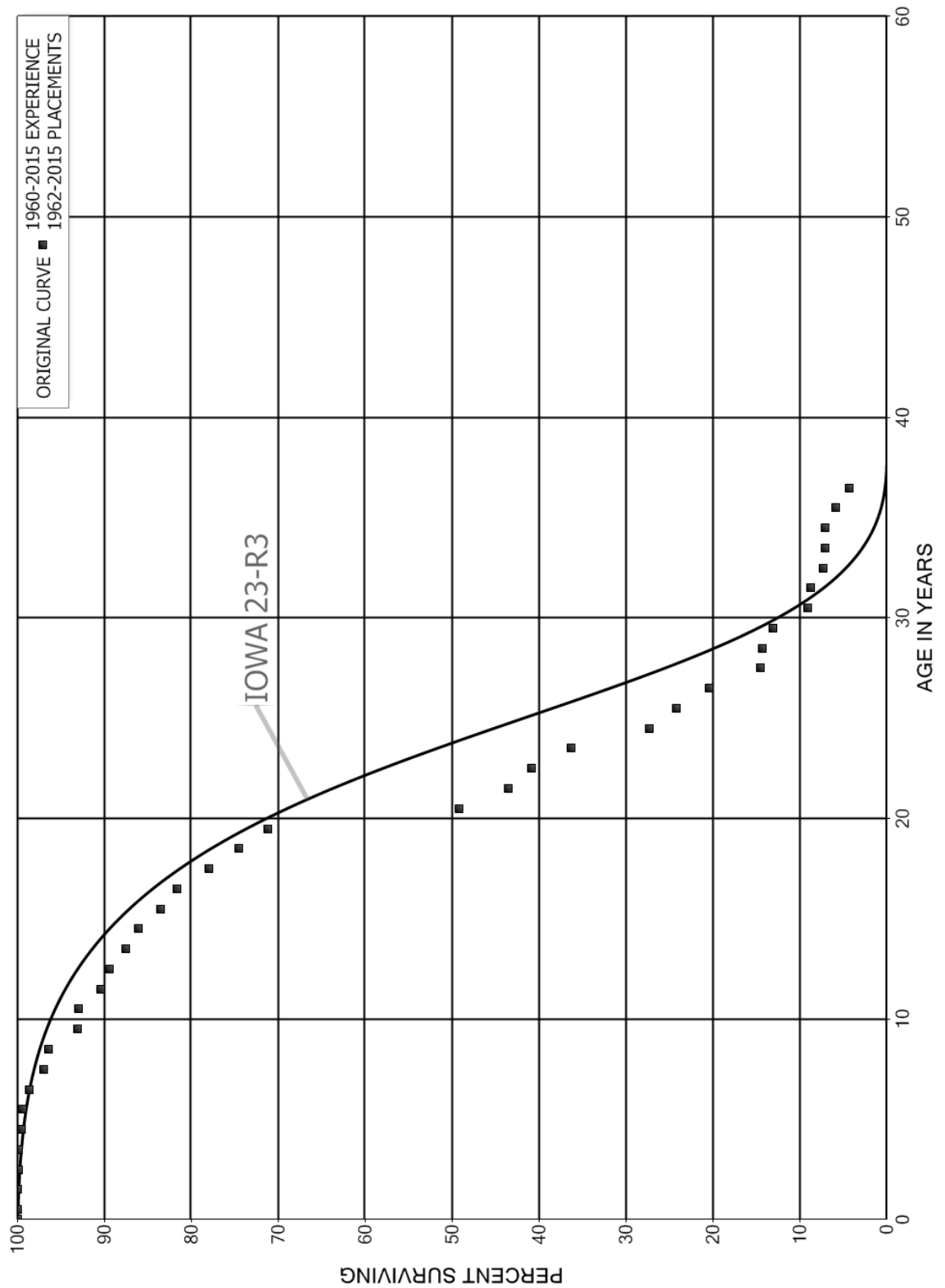
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1961-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	42,738	15,000	0.0000	1.0000	3.14
40.5	42,738		0.3510	0.6490	3.14
41.5	27,738		0.0000	1.0000	2.04
42.5	27,738		0.0000	1.0000	2.04
43.5	27,738		0.0000	1.0000	2.04
44.5	27,738		0.0000	1.0000	2.04
45.5	27,738		0.0000	1.0000	2.04
46.5	27,738		0.0000	1.0000	2.04
47.5	27,738		0.0000	1.0000	2.04
48.5	27,738		0.0000	1.0000	2.04
49.5	27,738		0.0000	1.0000	2.04
50.5	27,738		0.0000	1.0000	2.04
51.5	27,738		0.0000	1.0000	2.04
52.5	27,738		0.0000	1.0000	2.04
53.5	27,738		0.0000	1.0000	2.04
54.5					2.04

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 343.00 - DIESEL - PRIME MOVERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 343.00 - DIESEL - PRIME MOVERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1960-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	91,739,944		0.0000	1.0000	100.00
0.5	91,265,124		0.0000	1.0000	100.00
1.5	86,735,804	157,969	0.0018	0.9982	100.00
2.5	76,158,290		0.0000	1.0000	99.82
3.5	73,925,717	243,540	0.0033	0.9967	99.82
4.5	69,232,945	96,980	0.0014	0.9986	99.49
5.5	68,034,510	521,053	0.0077	0.9923	99.35
6.5	66,952,386	1,088,913	0.0163	0.9837	98.59
7.5	64,915,336	397,153	0.0061	0.9939	96.99
8.5	59,901,835	2,054,125	0.0343	0.9657	96.39
9.5	54,822,357	73,280	0.0013	0.9987	93.09
10.5	52,193,369	1,440,004	0.0276	0.9724	92.96
11.5	50,746,377	552,648	0.0109	0.9891	90.40
12.5	49,013,964	1,050,984	0.0214	0.9786	89.41
13.5	46,602,332	738,300	0.0158	0.9842	87.50
14.5	40,247,686	1,236,802	0.0307	0.9693	86.11
15.5	33,051,926	718,451	0.0217	0.9783	83.46
16.5	32,333,475	1,441,432	0.0446	0.9554	81.65
17.5	29,898,507	1,333,267	0.0446	0.9554	78.01
18.5	24,878,452	1,102,127	0.0443	0.9557	74.53
19.5	19,434,382	6,013,659	0.3094	0.6906	71.23
20.5	11,295,325	1,306,536	0.1157	0.8843	49.19
21.5	9,988,790	616,980	0.0618	0.9382	43.50
22.5	9,371,809	1,031,282	0.1100	0.8900	40.81
23.5	8,340,527	2,069,331	0.2481	0.7519	36.32
24.5	6,271,196	707,867	0.1129	0.8871	27.31
25.5	5,563,329	876,474	0.1575	0.8425	24.23
26.5	4,686,855	1,365,705	0.2914	0.7086	20.41
27.5	3,321,149	49,055	0.0148	0.9852	14.46
28.5	3,272,095	278,457	0.0851	0.9149	14.25
29.5	2,993,637	910,885	0.3043	0.6957	13.04
30.5	2,082,752	85,276	0.0409	0.9591	9.07
31.5	1,997,476	312,825	0.1566	0.8434	8.70
32.5	1,684,651	56,606	0.0336	0.9664	7.34
33.5	1,628,044		0.0000	1.0000	7.09
34.5	1,628,044	287,839	0.1768	0.8232	7.09
35.5	1,340,205	367,663	0.2743	0.7257	5.84
36.5	972,542	894,614	0.9199	0.0801	4.24
37.5	77,929	2,748	0.0353	0.9647	0.34
38.5	75,181	44,137	0.5871	0.4129	0.33

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 343.00 - DIESEL - PRIME MOVERS

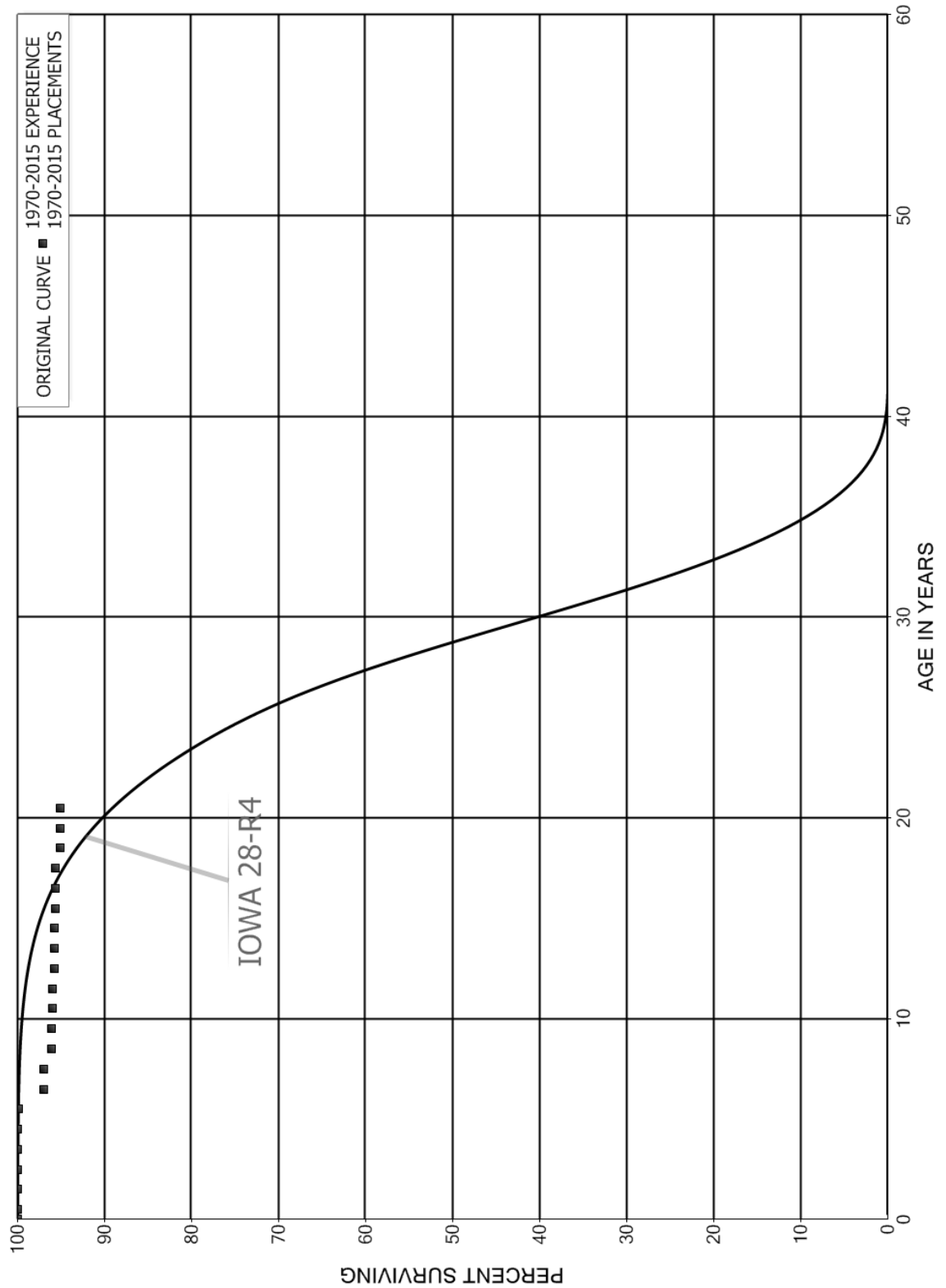
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1960-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	28,844	16,000	0.0000	1.0000	0.14
40.5	28,844		0.5547	0.4453	0.14
41.5	12,844		0.0000	1.0000	0.06
42.5	12,844		0.0000	1.0000	0.06
43.5	12,844		0.0000	1.0000	0.06
44.5	12,844		0.0000	1.0000	0.06
45.5	12,844		0.0000	1.0000	0.06
46.5	12,844		0.0000	1.0000	0.06
47.5	12,844		0.0000	1.0000	0.06
48.5	12,844		0.0000	1.0000	0.06
49.5	12,844		0.0000	1.0000	0.06
50.5	12,844		0.0000	1.0000	0.06
51.5	12,844		0.0000	1.0000	0.06
52.5	12,844		0.0000	1.0000	0.06
53.5					0.06

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 344.00 - DIESEL - GENERATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 344.00 - DIESEL - GENERATORS

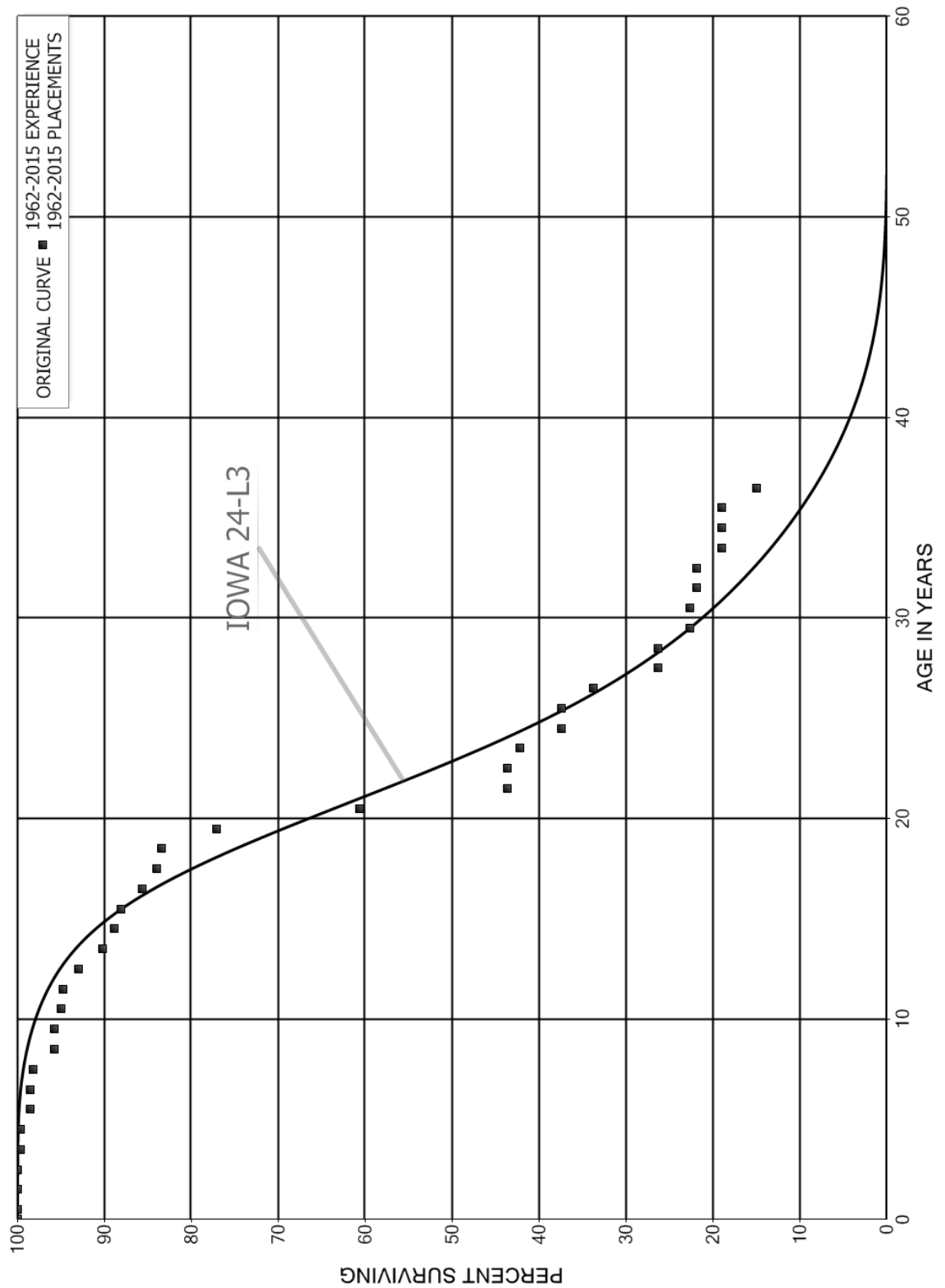
ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2015

EXPERIENCE BAND 1970-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,204,436		0.0000	1.0000	100.00
0.5	11,794,529		0.0000	1.0000	100.00
1.5	11,128,479		0.0000	1.0000	100.00
2.5	11,067,948		0.0000	1.0000	100.00
3.5	11,067,948		0.0000	1.0000	100.00
4.5	10,643,996	22,000	0.0021	0.9979	100.00
5.5	10,621,996	305,983	0.0288	0.9712	99.79
6.5	10,316,013		0.0000	1.0000	96.92
7.5	10,316,013	90,433	0.0088	0.9912	96.92
8.5	9,694,663		0.0000	1.0000	96.07
9.5	7,804,483	5,022	0.0006	0.9994	96.07
10.5	7,091,934		0.0000	1.0000	96.01
11.5	7,091,934	24,241	0.0034	0.9966	96.01
12.5	6,929,006		0.0000	1.0000	95.68
13.5	6,692,329		0.0000	1.0000	95.68
14.5	6,572,741	2,245	0.0003	0.9997	95.68
15.5	5,594,436		0.0000	1.0000	95.65
16.5	4,526,369		0.0000	1.0000	95.65
17.5	4,364,837	28,651	0.0066	0.9934	95.65
18.5	3,038,559		0.0000	1.0000	95.02
19.5	1,224,273		0.0000	1.0000	95.02
20.5	23,066		0.0000	1.0000	95.02
21.5	23,066		0.0000	1.0000	95.02
22.5	23,066		0.0000	1.0000	95.02
23.5	22,437	6,397	0.2851	0.7149	95.02
24.5	16,039		0.0000	1.0000	67.93
25.5	16,039		0.0000	1.0000	67.93
26.5	16,039		0.0000	1.0000	67.93
27.5	16,039		0.0000	1.0000	67.93
28.5	16,039		0.0000	1.0000	67.93
29.5	16,039	16,039	1.0000		67.93
30.5					

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 345.00 - DIESEL - ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 345.00 - DIESEL - ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,270,812		0.0000	1.0000	100.00
0.5	26,772,261		0.0000	1.0000	100.00
1.5	25,147,179		0.0000	1.0000	100.00
2.5	23,702,096	84,499	0.0036	0.9964	100.00
3.5	22,965,784	1,000	0.0000	1.0000	99.64
4.5	20,480,332	233,912	0.0114	0.9886	99.64
5.5	18,796,638	6,000	0.0003	0.9997	98.50
6.5	18,649,831	50,634	0.0027	0.9973	98.47
7.5	18,010,823	455,746	0.0253	0.9747	98.20
8.5	15,566,210	7,031	0.0005	0.9995	95.72
9.5	14,486,702	106,988	0.0074	0.9926	95.67
10.5	13,147,669	34,555	0.0026	0.9974	94.97
11.5	13,113,114	247,207	0.0189	0.9811	94.72
12.5	12,403,792	364,263	0.0294	0.9706	92.93
13.5	11,357,922	171,818	0.0151	0.9849	90.20
14.5	10,838,963	99,949	0.0092	0.9908	88.84
15.5	9,350,947	260,202	0.0278	0.9722	88.02
16.5	7,960,944	152,606	0.0192	0.9808	85.57
17.5	5,612,403	33,277	0.0059	0.9941	83.93
18.5	4,065,072	308,217	0.0758	0.9242	83.43
19.5	2,103,347	449,630	0.2138	0.7862	77.11
20.5	1,169,076	328,642	0.2811	0.7189	60.62
21.5	840,434		0.0000	1.0000	43.58
22.5	840,434	27,793	0.0331	0.9669	43.58
23.5	812,640	90,808	0.1117	0.8883	42.14
24.5	721,832		0.0000	1.0000	37.43
25.5	721,832	72,000	0.0997	0.9003	37.43
26.5	649,832	142,395	0.2191	0.7809	33.70
27.5	507,437		0.0000	1.0000	26.31
28.5	507,437	71,879	0.1417	0.8583	26.31
29.5	435,558		0.0000	1.0000	22.59
30.5	435,558	14,525	0.0333	0.9667	22.59
31.5	421,033		0.0000	1.0000	21.83
32.5	410,923	54,401	0.1324	0.8676	21.83
33.5	356,522		0.0000	1.0000	18.94
34.5	356,522		0.0000	1.0000	18.94
35.5	356,522	75,557	0.2119	0.7881	18.94
36.5	280,965	110,000	0.3915	0.6085	14.93
37.5	170,965	101,656	0.5946	0.4054	9.08
38.5	69,309	27,254	0.3932	0.6068	3.68

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 345.00 - DIESEL - ACCESSORY ELECTRIC EQUIPMENT

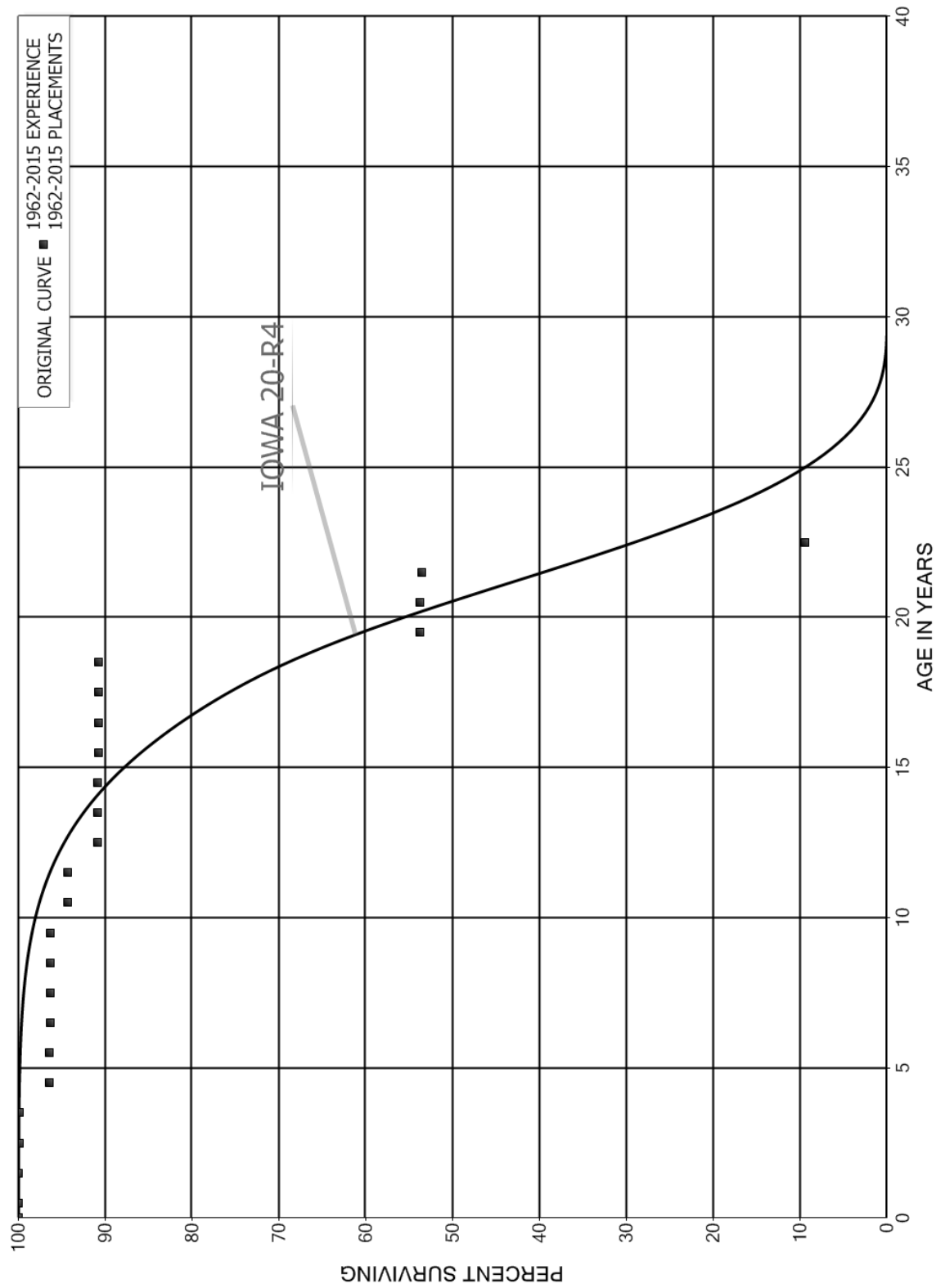
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	42,055		0.0000	1.0000	2.23
40.5	42,055	14,678	0.3490	0.6510	2.23
41.5	27,377		0.0000	1.0000	1.45
42.5	27,377		0.0000	1.0000	1.45
43.5	27,377		0.0000	1.0000	1.45
44.5	27,377	14,801	0.5406	0.4594	1.45
45.5	12,576		0.0000	1.0000	0.67
46.5	12,576		0.0000	1.0000	0.67
47.5	12,576		0.0000	1.0000	0.67
48.5	12,576		0.0000	1.0000	0.67
49.5	12,576		0.0000	1.0000	0.67
50.5					0.67

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 346.00 - DIESEL - MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 346.00 - DIESEL - MISCELLANEOUS POWER PLANT EQUIPMENT

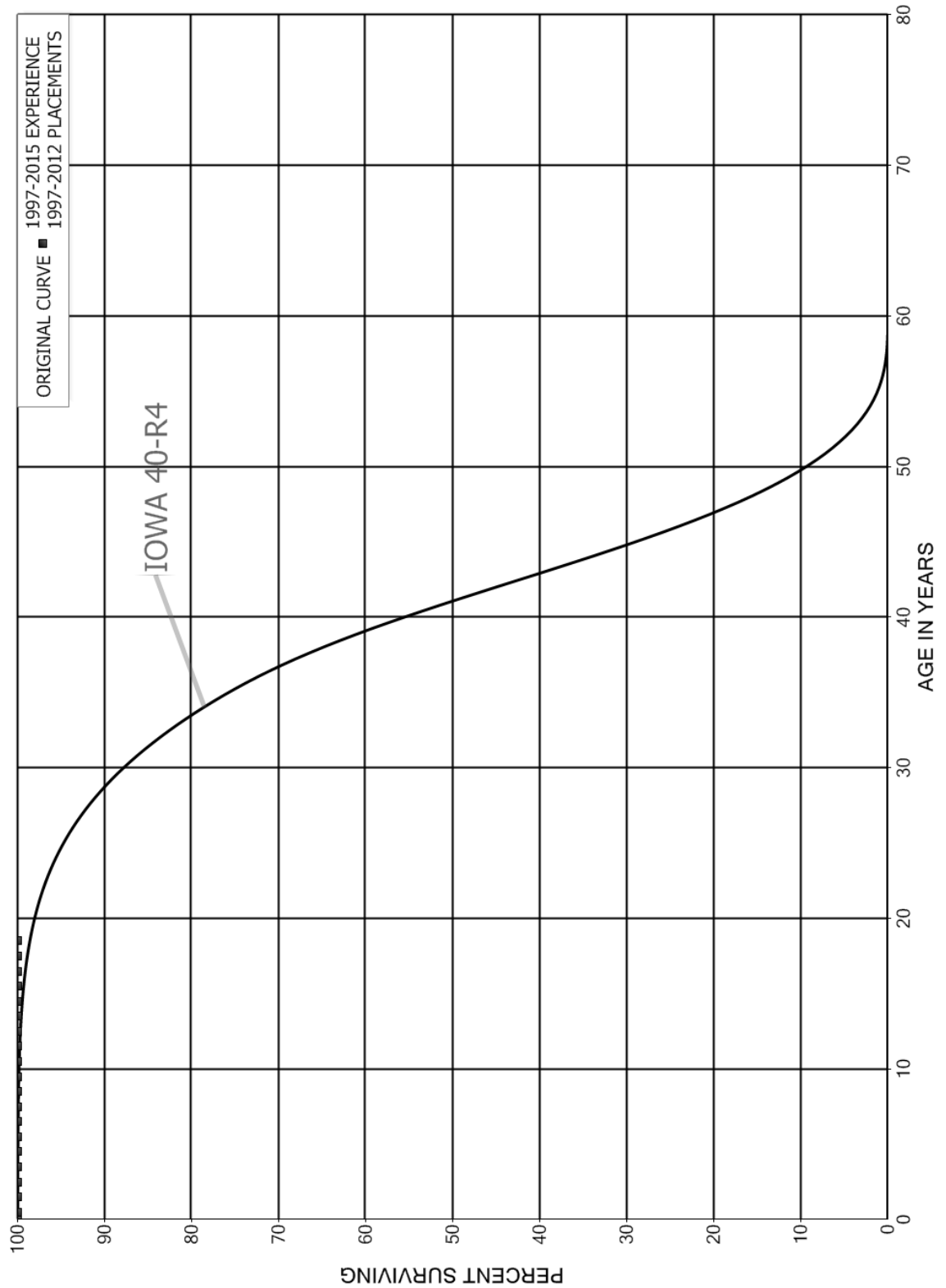
ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,116,789		0.0000	1.0000	100.00
0.5	3,030,020		0.0000	1.0000	100.00
1.5	2,950,366	4,904	0.0017	0.9983	100.00
2.5	2,511,260		0.0000	1.0000	99.83
3.5	2,511,260	87,187	0.0347	0.9653	99.83
4.5	2,413,889		0.0000	1.0000	96.37
5.5	2,413,889	1,499	0.0006	0.9994	96.37
6.5	2,259,321		0.0000	1.0000	96.31
7.5	2,059,739	466	0.0002	0.9998	96.31
8.5	2,004,240		0.0000	1.0000	96.29
9.5	1,893,213	39,062	0.0206	0.9794	96.29
10.5	1,841,997		0.0000	1.0000	94.30
11.5	1,841,997	68,060	0.0369	0.9631	94.30
12.5	1,753,388		0.0000	1.0000	90.82
13.5	1,725,659		0.0000	1.0000	90.82
14.5	1,725,659	1,000	0.0006	0.9994	90.82
15.5	1,701,188		0.0000	1.0000	90.76
16.5	1,686,472		0.0000	1.0000	90.76
17.5	1,233,986		0.0000	1.0000	90.76
18.5	1,056,784	430,908	0.4078	0.5922	90.76
19.5	265,728	373	0.0014	0.9986	53.75
20.5	105,740	441	0.0042	0.9958	53.68
21.5	105,299	86,738	0.8237	0.1763	53.45
22.5	18,561		0.0000	1.0000	9.42
23.5	18,561		0.0000	1.0000	9.42
24.5	18,561		0.0000	1.0000	9.42
25.5	18,561		0.0000	1.0000	9.42
26.5	18,561	12,207	0.6577	0.3423	9.42
27.5	6,354		0.0000	1.0000	3.23
28.5	6,354		0.0000	1.0000	3.23
29.5	6,354		0.0000	1.0000	3.23
30.5	6,354		0.0000	1.0000	3.23
31.5	6,354		0.0000	1.0000	3.23
32.5	6,354		0.0000	1.0000	3.23
33.5	6,354	6,354	1.0000		3.23
34.5					

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 352.00 - TRANSMISSION - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 352.00 - TRANSMISSION - STRUCTURES AND IMPROVEMENTS

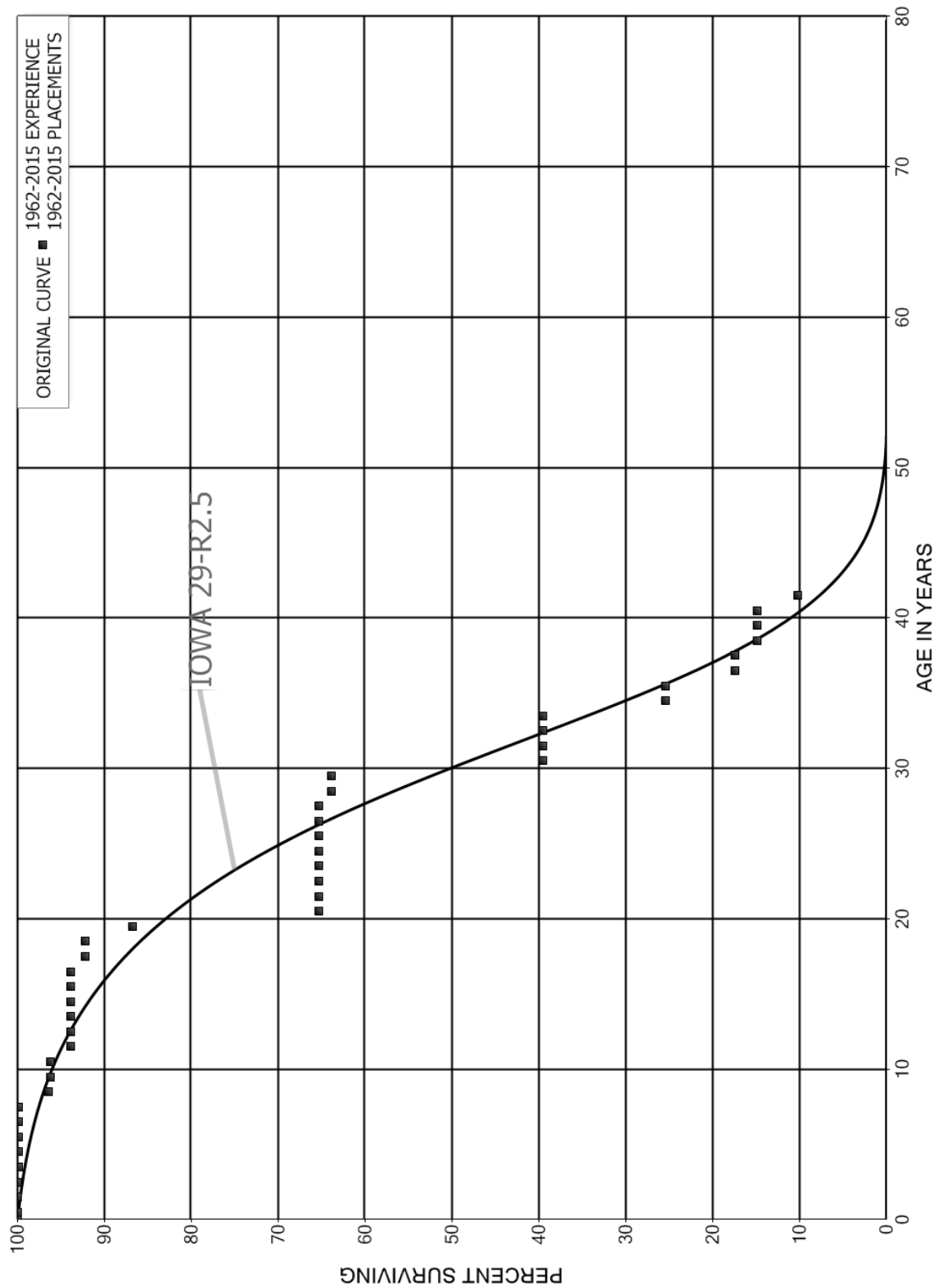
ORIGINAL LIFE TABLE

PLACEMENT BAND 1997-2012

EXPERIENCE BAND 1997-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	847,175		0.0000	1.0000	100.00
0.5	847,175		0.0000	1.0000	100.00
1.5	847,175		0.0000	1.0000	100.00
2.5	847,175		0.0000	1.0000	100.00
3.5	843,794		0.0000	1.0000	100.00
4.5	843,794		0.0000	1.0000	100.00
5.5	843,794		0.0000	1.0000	100.00
6.5	467,053		0.0000	1.0000	100.00
7.5	368,371		0.0000	1.0000	100.00
8.5	368,371		0.0000	1.0000	100.00
9.5	368,371		0.0000	1.0000	100.00
10.5	365,739		0.0000	1.0000	100.00
11.5	365,739		0.0000	1.0000	100.00
12.5	365,739		0.0000	1.0000	100.00
13.5	263,132		0.0000	1.0000	100.00
14.5	221,965		0.0000	1.0000	100.00
15.5	219,109		0.0000	1.0000	100.00
16.5	219,109		0.0000	1.0000	100.00
17.5	76,027		0.0000	1.0000	100.00
18.5					100.00

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 353.00 - TRANSMISSION - STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 353.00 - TRANSMISSION - STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,293,052		0.0000	1.0000	100.00
0.5	10,738,840		0.0000	1.0000	100.00
1.5	10,141,971		0.0000	1.0000	100.00
2.5	10,082,798	13,675	0.0014	0.9986	100.00
3.5	10,069,124		0.0000	1.0000	99.86
4.5	9,182,759		0.0000	1.0000	99.86
5.5	8,650,308		0.0000	1.0000	99.86
6.5	8,650,308		0.0000	1.0000	99.86
7.5	8,521,488	298,862	0.0351	0.9649	99.86
8.5	7,552,839	12,776	0.0017	0.9983	96.36
9.5	7,219,844		0.0000	1.0000	96.20
10.5	7,037,203	170,797	0.0243	0.9757	96.20
11.5	6,866,406		0.0000	1.0000	93.86
12.5	6,204,945		0.0000	1.0000	93.86
13.5	5,811,505	1,518	0.0003	0.9997	93.86
14.5	3,227,375		0.0000	1.0000	93.84
15.5	2,246,543		0.0000	1.0000	93.84
16.5	2,104,317	38,138	0.0181	0.9819	93.84
17.5	1,142,982		0.0000	1.0000	92.14
18.5	1,097,652	64,050	0.0584	0.9416	92.14
19.5	1,019,635	252,894	0.2480	0.7520	86.76
20.5	763,658		0.0000	1.0000	65.24
21.5	763,658		0.0000	1.0000	65.24
22.5	763,658		0.0000	1.0000	65.24
23.5	763,658		0.0000	1.0000	65.24
24.5	763,658		0.0000	1.0000	65.24
25.5	763,658		0.0000	1.0000	65.24
26.5	763,658		0.0000	1.0000	65.24
27.5	763,658	16,976	0.0222	0.9778	65.24
28.5	746,682		0.0000	1.0000	63.79
29.5	746,682	284,759	0.3814	0.6186	63.79
30.5	461,923		0.0000	1.0000	39.46
31.5	461,923		0.0000	1.0000	39.46
32.5	461,923		0.0000	1.0000	39.46
33.5	461,923	164,493	0.3561	0.6439	39.46
34.5	297,430		0.0000	1.0000	25.41
35.5	297,430	93,390	0.3140	0.6860	25.41
36.5	204,040		0.0000	1.0000	17.43
37.5	204,040	29,910	0.1466	0.8534	17.43
38.5	174,130		0.0000	1.0000	14.88

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 353.00 - TRANSMISSION - STATION EQUIPMENT

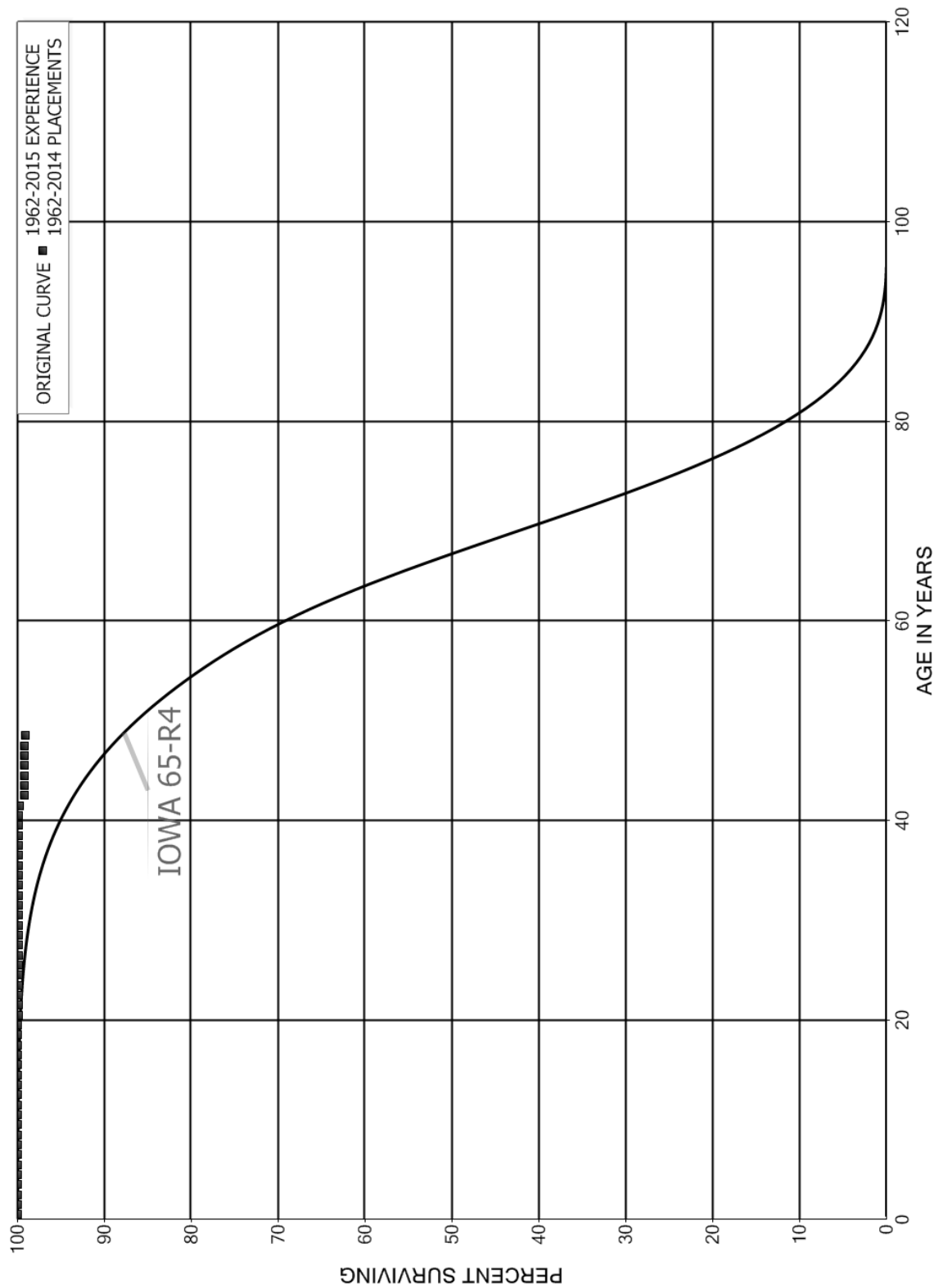
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	174,130		0.0000	1.0000	14.88
40.5	174,130	55,417	0.3183	0.6817	14.88
41.5	118,713	103,430	0.8713	0.1287	10.14
42.5	15,283		0.0000	1.0000	1.31
43.5	15,283		0.0000	1.0000	1.31
44.5	15,283		0.0000	1.0000	1.31
45.5	15,283		0.0000	1.0000	1.31
46.5	15,283		0.0000	1.0000	1.31
47.5	15,283	15,283	1.0000		1.31
48.5					

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 354.00 - TRANSMISSION - TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 354.00 - TRANSMISSION - TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2014

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,396,761		0.0000	1.0000	100.00
0.5	14,396,761		0.0000	1.0000	100.00
1.5	14,326,307		0.0000	1.0000	100.00
2.5	14,232,519		0.0000	1.0000	100.00
3.5	14,232,519		0.0000	1.0000	100.00
4.5	14,232,519		0.0000	1.0000	100.00
5.5	14,232,519		0.0000	1.0000	100.00
6.5	14,232,519		0.0000	1.0000	100.00
7.5	14,232,519		0.0000	1.0000	100.00
8.5	14,078,552		0.0000	1.0000	100.00
9.5	14,078,189		0.0000	1.0000	100.00
10.5	14,078,189		0.0000	1.0000	100.00
11.5	14,078,189		0.0000	1.0000	100.00
12.5	14,071,305		0.0000	1.0000	100.00
13.5	14,036,273		0.0000	1.0000	100.00
14.5	13,991,680		0.0000	1.0000	100.00
15.5	13,991,680		0.0000	1.0000	100.00
16.5	13,991,680		0.0000	1.0000	100.00
17.5	13,286,771		0.0000	1.0000	100.00
18.5	13,258,993		0.0000	1.0000	100.00
19.5	13,258,993	20,446	0.0015	0.9985	100.00
20.5	13,204,528		0.0000	1.0000	99.85
21.5	12,922,343		0.0000	1.0000	99.85
22.5	12,629,698		0.0000	1.0000	99.85
23.5	12,123,098		0.0000	1.0000	99.85
24.5	12,123,098		0.0000	1.0000	99.85
25.5	2,158,090		0.0000	1.0000	99.85
26.5	2,158,090		0.0000	1.0000	99.85
27.5	2,158,090		0.0000	1.0000	99.85
28.5	2,158,090		0.0000	1.0000	99.85
29.5	2,158,090		0.0000	1.0000	99.85
30.5	2,158,090		0.0000	1.0000	99.85
31.5	2,158,090		0.0000	1.0000	99.85
32.5	2,158,090		0.0000	1.0000	99.85
33.5	2,158,090		0.0000	1.0000	99.85
34.5	2,158,090		0.0000	1.0000	99.85
35.5	2,118,733		0.0000	1.0000	99.85
36.5	2,118,733		0.0000	1.0000	99.85
37.5	1,593,602		0.0000	1.0000	99.85
38.5	1,593,602		0.0000	1.0000	99.85

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 354.00 - TRANSMISSION - TOWERS AND FIXTURES

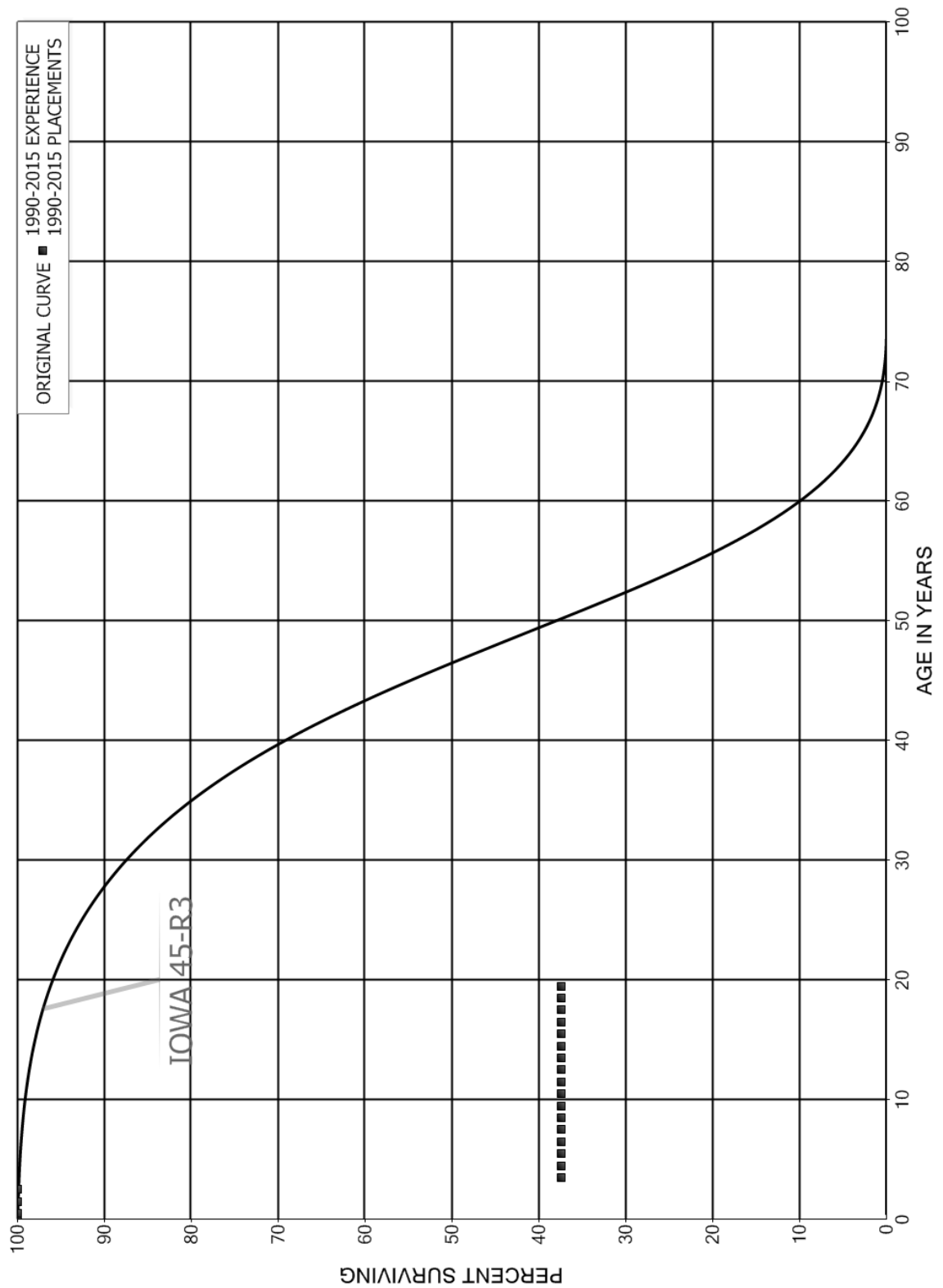
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2014

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,568,115		0.0000	1.0000	99.85
40.5	1,568,115	1,059	0.0007	0.9993	99.85
41.5	1,567,056	9,017	0.0058	0.9942	99.78
42.5	1,539,142		0.0000	1.0000	99.20
43.5	1,539,142		0.0000	1.0000	99.20
44.5	1,473,930		0.0000	1.0000	99.20
45.5	1,473,930		0.0000	1.0000	99.20
46.5	1,074,555		0.0000	1.0000	99.20
47.5	1,074,555	1,374	0.0013	0.9987	99.20
48.5	117,772		0.0000	1.0000	99.08
49.5	117,772		0.0000	1.0000	99.08
50.5	117,772		0.0000	1.0000	99.08
51.5	117,772		0.0000	1.0000	99.08
52.5	117,772		0.0000	1.0000	99.08
53.5					99.08

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 355.00 - TRANSMISSION - POLES AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

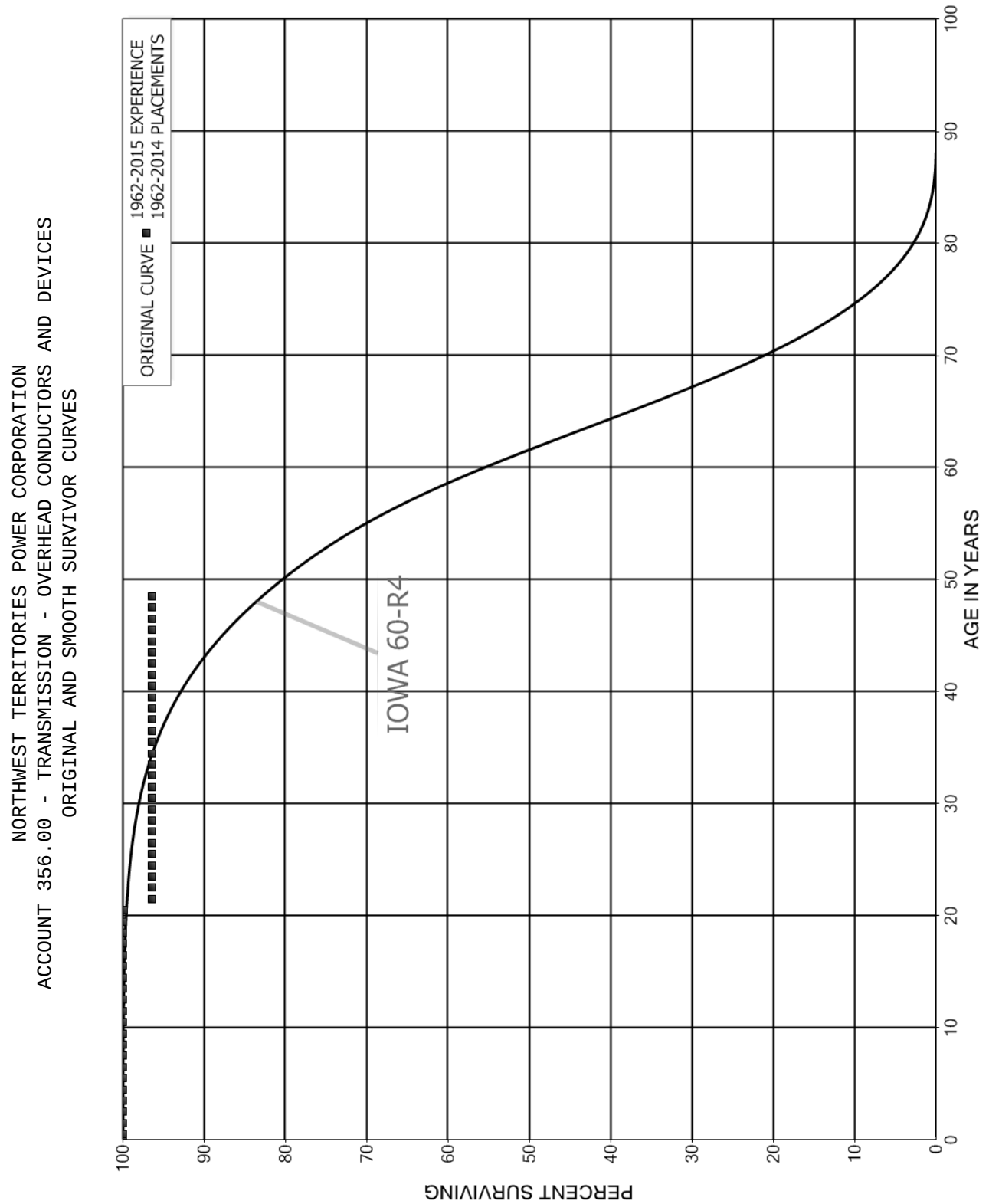
ACCOUNT 355.00 - TRANSMISSION - POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1990-2015

EXPERIENCE BAND 1990-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,226,708	1,913,566	0.0000	1.0000	100.00
0.5	3,114,113		0.0000	1.0000	100.00
1.5	3,054,190		0.0000	1.0000	100.00
2.5	3,054,190		0.6265	0.3735	100.00
3.5	1,140,624		0.0000	1.0000	37.35
4.5	1,140,624		0.0000	1.0000	37.35
5.5	1,140,624		0.0000	1.0000	37.35
6.5	1,140,624		0.0000	1.0000	37.35
7.5	753,262		0.0000	1.0000	37.35
8.5	753,262		0.0000	1.0000	37.35
9.5	753,262		0.0000	1.0000	37.35
10.5	753,262		0.0000	1.0000	37.35
11.5	753,262		0.0000	1.0000	37.35
12.5	753,262		0.0000	1.0000	37.35
13.5	753,262		0.0000	1.0000	37.35
14.5	738,342		0.0000	1.0000	37.35
15.5	378,629		0.0000	1.0000	37.35
16.5	320,188		0.0000	1.0000	37.35
17.5	200,370		0.0000	1.0000	37.35
18.5	187,133		0.0000	1.0000	37.35
19.5					37.35



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 356.00 - TRANSMISSION - OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2014

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,143,739		0.0000	1.0000	100.00
0.5	11,143,739		0.0000	1.0000	100.00
1.5	10,925,382		0.0000	1.0000	100.00
2.5	10,925,382		0.0000	1.0000	100.00
3.5	10,925,382		0.0000	1.0000	100.00
4.5	10,925,382		0.0000	1.0000	100.00
5.5	10,925,382		0.0000	1.0000	100.00
6.5	10,925,382		0.0000	1.0000	100.00
7.5	9,721,703		0.0000	1.0000	100.00
8.5	9,721,703		0.0000	1.0000	100.00
9.5	9,721,703		0.0000	1.0000	100.00
10.5	9,721,703		0.0000	1.0000	100.00
11.5	9,721,703		0.0000	1.0000	100.00
12.5	9,721,703		0.0000	1.0000	100.00
13.5	9,721,703		0.0000	1.0000	100.00
14.5	9,721,703		0.0000	1.0000	100.00
15.5	8,533,527		0.0000	1.0000	100.00
16.5	8,506,722		0.0000	1.0000	100.00
17.5	8,046,476		0.0000	1.0000	100.00
18.5	7,906,833		0.0000	1.0000	100.00
19.5	7,906,833	12,268	0.0016	0.9984	100.00
20.5	7,894,565	274,019	0.0347	0.9653	99.84
21.5	7,620,547		0.0000	1.0000	96.38
22.5	7,620,547		0.0000	1.0000	96.38
23.5	7,316,587		0.0000	1.0000	96.38
24.5	6,999,839		0.0000	1.0000	96.38
25.5	1,294,853		0.0000	1.0000	96.38
26.5	1,294,853		0.0000	1.0000	96.38
27.5	1,294,853		0.0000	1.0000	96.38
28.5	1,294,853		0.0000	1.0000	96.38
29.5	1,294,853		0.0000	1.0000	96.38
30.5	1,294,853		0.0000	1.0000	96.38
31.5	1,294,853		0.0000	1.0000	96.38
32.5	1,294,853		0.0000	1.0000	96.38
33.5	1,294,853		0.0000	1.0000	96.38
34.5	1,294,853		0.0000	1.0000	96.38
35.5	1,271,239		0.0000	1.0000	96.38
36.5	1,271,239		0.0000	1.0000	96.38
37.5	956,160		0.0000	1.0000	96.38
38.5	956,160		0.0000	1.0000	96.38

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 356.00 - TRANSMISSION - OVERHEAD CONDUCTORS AND DEVICES

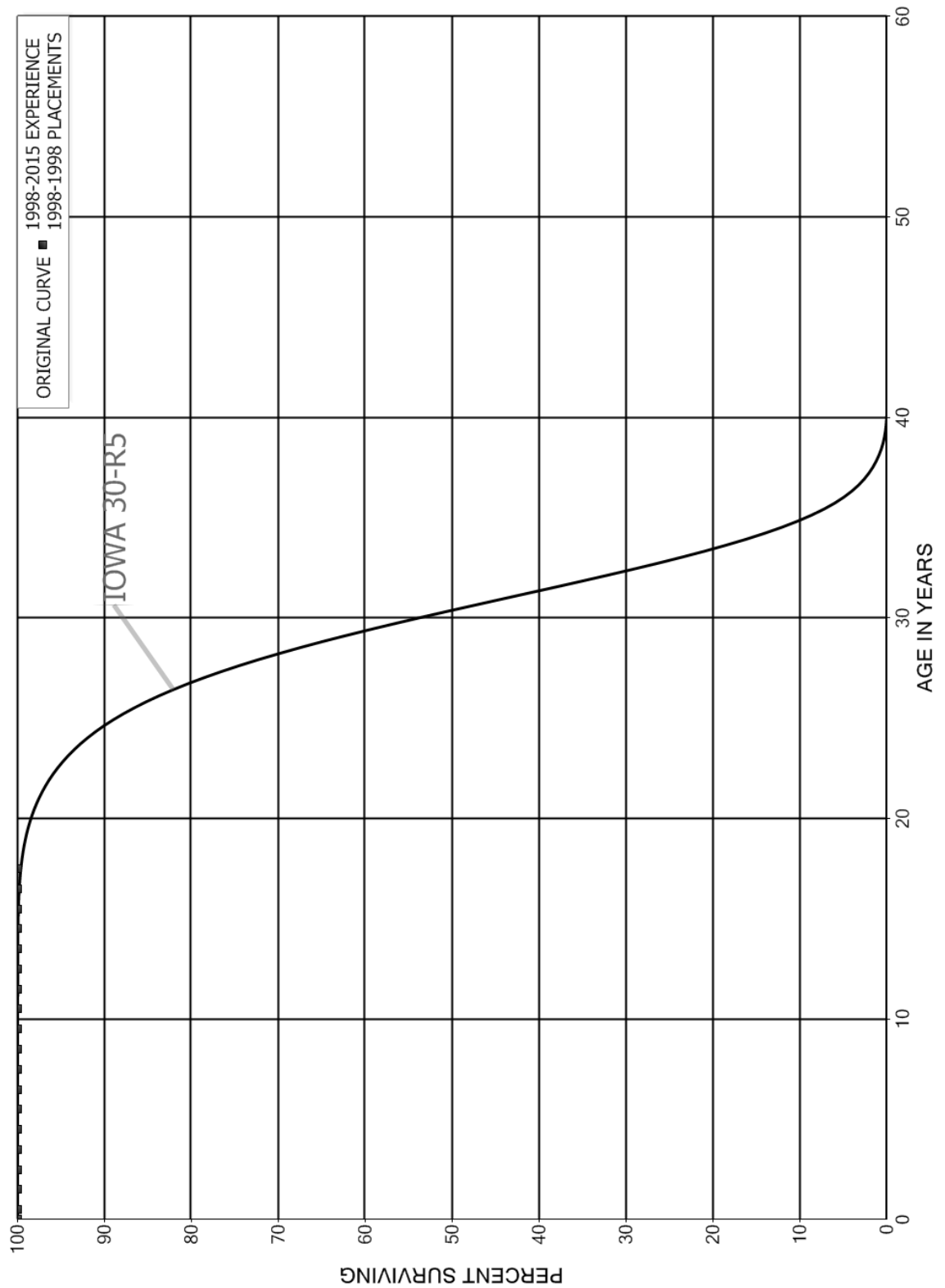
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2014

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	940,869		0.0000	1.0000	96.38
40.5	940,869		0.0000	1.0000	96.38
41.5	940,869		0.0000	1.0000	96.38
42.5	929,531		0.0000	1.0000	96.38
43.5	929,531		0.0000	1.0000	96.38
44.5	890,404		0.0000	1.0000	96.38
45.5	890,404		0.0000	1.0000	96.38
46.5	650,779		0.0000	1.0000	96.38
47.5	650,779		0.0000	1.0000	96.38
48.5	76,709		0.0000	1.0000	96.38
49.5	76,709		0.0000	1.0000	96.38
50.5	76,709		0.0000	1.0000	96.38
51.5	76,709		0.0000	1.0000	96.38
52.5	76,709		0.0000	1.0000	96.38
53.5					96.38

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 357.00 - TRANSMISSION - UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 357.00 - TRANSMISSION - UNDERGROUND CONDUIT

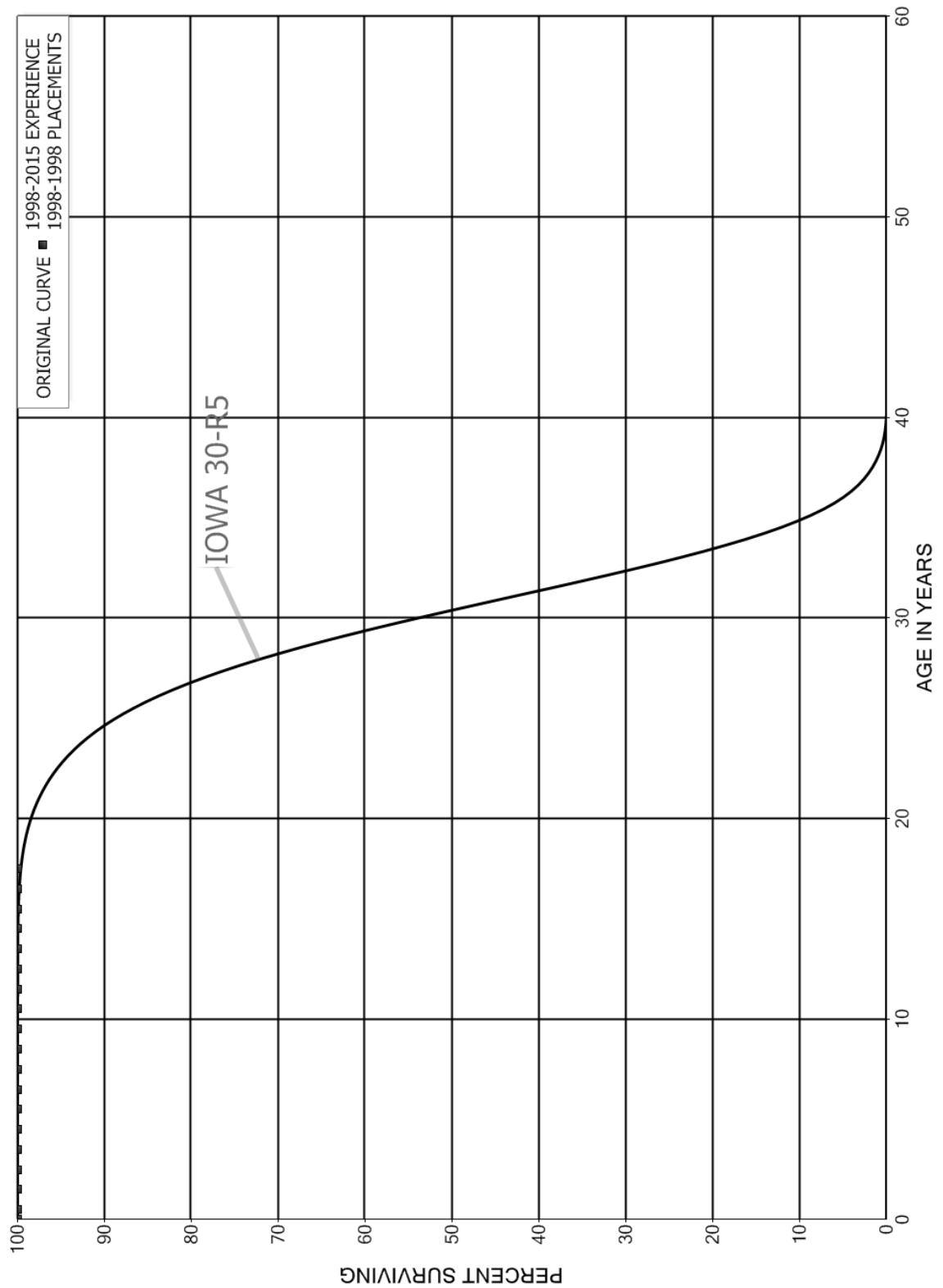
ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-1998

EXPERIENCE BAND 1998-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,434		0.0000	1.0000	100.00
0.5	12,434		0.0000	1.0000	100.00
1.5	12,434		0.0000	1.0000	100.00
2.5	12,434		0.0000	1.0000	100.00
3.5	12,434		0.0000	1.0000	100.00
4.5	12,434		0.0000	1.0000	100.00
5.5	12,434		0.0000	1.0000	100.00
6.5	12,434		0.0000	1.0000	100.00
7.5	12,434		0.0000	1.0000	100.00
8.5	12,434		0.0000	1.0000	100.00
9.5	12,434		0.0000	1.0000	100.00
10.5	12,434		0.0000	1.0000	100.00
11.5	12,434		0.0000	1.0000	100.00
12.5	12,434		0.0000	1.0000	100.00
13.5	12,434		0.0000	1.0000	100.00
14.5	12,434		0.0000	1.0000	100.00
15.5	12,434		0.0000	1.0000	100.00
16.5	12,434		0.0000	1.0000	100.00
17.5					100.00

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 358.00 - TRANSMISSION - UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 358.00 - TRANSMISSION - UNDERGROUND CONDUCTORS AND DEVICES

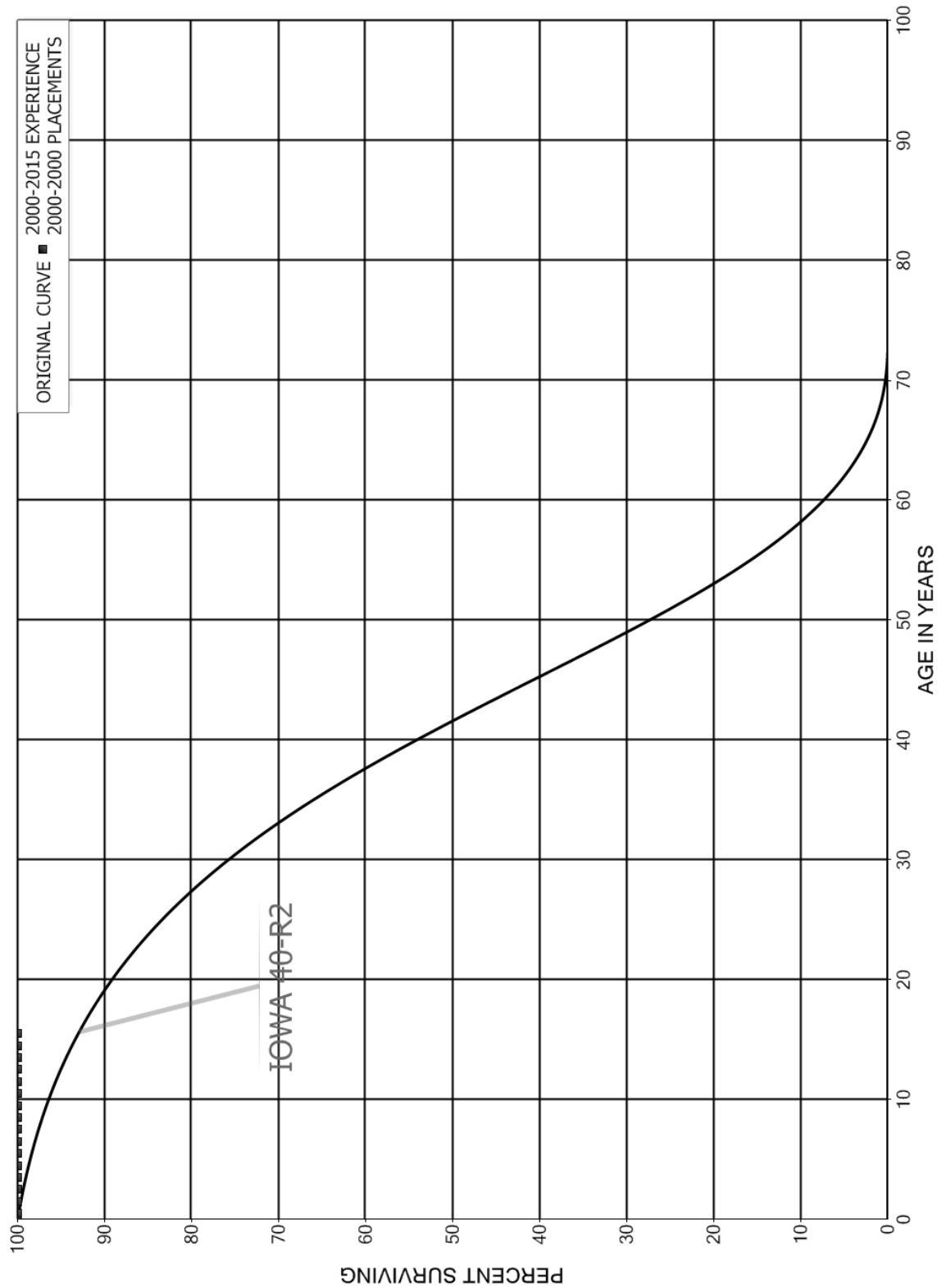
ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-1998

EXPERIENCE BAND 1998-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,344		0.0000	1.0000	100.00
0.5	16,344		0.0000	1.0000	100.00
1.5	16,344		0.0000	1.0000	100.00
2.5	16,344		0.0000	1.0000	100.00
3.5	16,344		0.0000	1.0000	100.00
4.5	16,344		0.0000	1.0000	100.00
5.5	16,344		0.0000	1.0000	100.00
6.5	16,344		0.0000	1.0000	100.00
7.5	16,344		0.0000	1.0000	100.00
8.5	16,344		0.0000	1.0000	100.00
9.5	16,344		0.0000	1.0000	100.00
10.5	16,344		0.0000	1.0000	100.00
11.5	16,344		0.0000	1.0000	100.00
12.5	16,344		0.0000	1.0000	100.00
13.5	16,344		0.0000	1.0000	100.00
14.5	16,344		0.0000	1.0000	100.00
15.5	16,344		0.0000	1.0000	100.00
16.5	16,344		0.0000	1.0000	100.00
17.5					100.00

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 359.00 - TRANSMISSION - ROADS AND TRAILS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 359.00 - TRANSMISSION - ROADS AND TRAILS

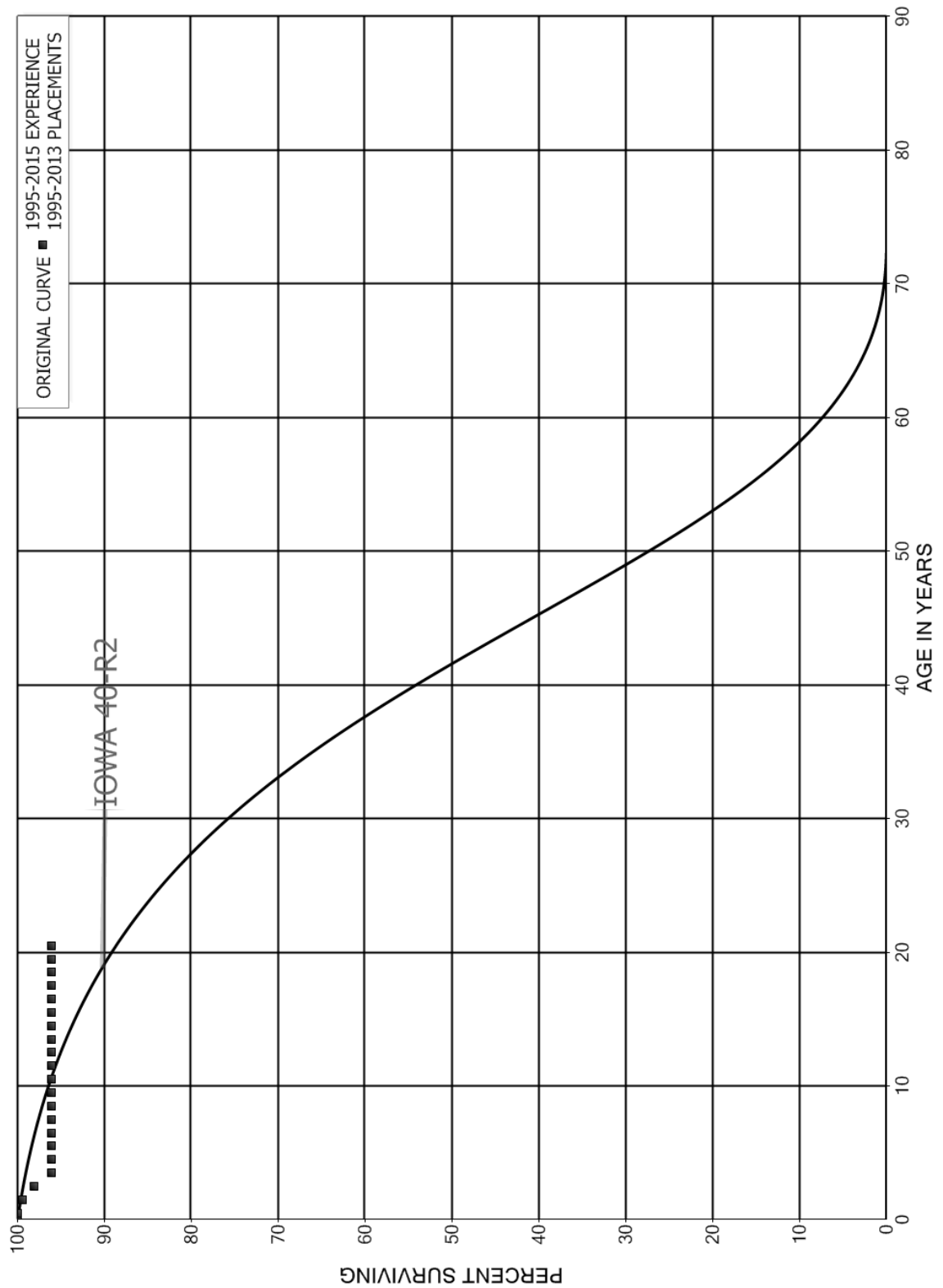
ORIGINAL LIFE TABLE

PLACEMENT BAND 2000-2000

EXPERIENCE BAND 2000-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	185,367		0.0000	1.0000	100.00
0.5	185,367		0.0000	1.0000	100.00
1.5	185,367		0.0000	1.0000	100.00
2.5	185,367		0.0000	1.0000	100.00
3.5	185,367		0.0000	1.0000	100.00
4.5	185,367		0.0000	1.0000	100.00
5.5	185,367		0.0000	1.0000	100.00
6.5	185,367		0.0000	1.0000	100.00
7.5	185,367		0.0000	1.0000	100.00
8.5	185,367		0.0000	1.0000	100.00
9.5	185,367		0.0000	1.0000	100.00
10.5	185,367		0.0000	1.0000	100.00
11.5	185,367		0.0000	1.0000	100.00
12.5	185,367		0.0000	1.0000	100.00
13.5	185,367		0.0000	1.0000	100.00
14.5	185,367		0.0000	1.0000	100.00
15.5					100.00

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 361.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 361.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

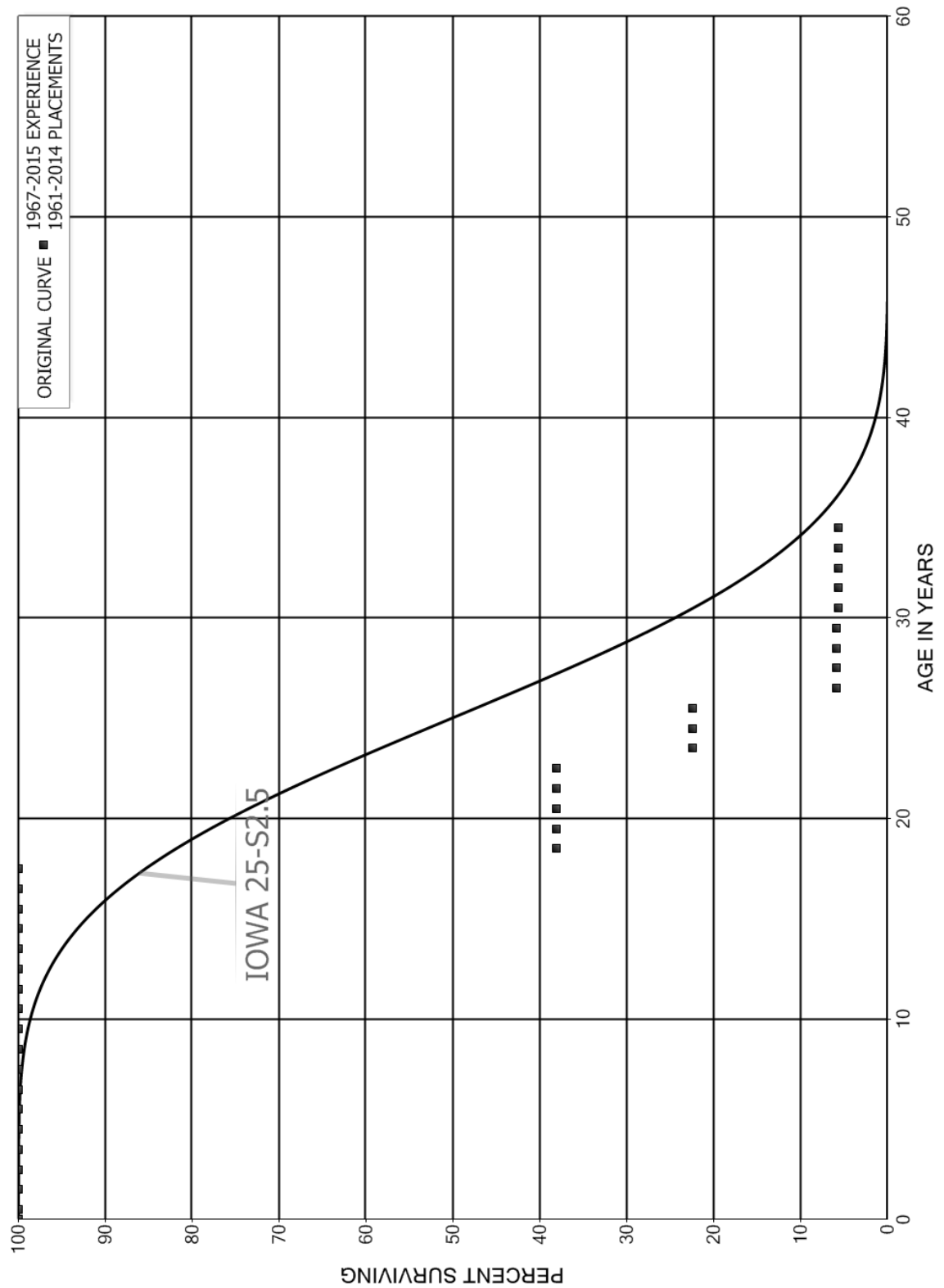
ORIGINAL LIFE TABLE

PLACEMENT BAND 1995-2013

EXPERIENCE BAND 1995-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	747,645		0.0000	1.0000	100.00
0.5	809,554	4,523	0.0056	0.9944	100.00
1.5	743,122	10,296	0.0139	0.9861	99.44
2.5	427,423	8,944	0.0209	0.9791	98.06
3.5	418,479		0.0000	1.0000	96.01
4.5	418,479		0.0000	1.0000	96.01
5.5	418,479		0.0000	1.0000	96.01
6.5	418,479		0.0000	1.0000	96.01
7.5	418,479		0.0000	1.0000	96.01
8.5	401,531		0.0000	1.0000	96.01
9.5	401,531		0.0000	1.0000	96.01
10.5	401,316		0.0000	1.0000	96.01
11.5	401,316		0.0000	1.0000	96.01
12.5	401,316		0.0000	1.0000	96.01
13.5	401,316		0.0000	1.0000	96.01
14.5	399,714		0.0000	1.0000	96.01
15.5	358,932		0.0000	1.0000	96.01
16.5	282,214		0.0000	1.0000	96.01
17.5	226,572		0.0000	1.0000	96.01
18.5	169,562		0.0000	1.0000	96.01
19.5	57,454		0.0000	1.0000	96.01
20.5					96.01

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 362.00 - DISTRIBUTION - STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 362.00 - DISTRIBUTION - STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1961-2014

EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,772,478		0.0000	1.0000	100.00
0.5	1,772,478		0.0000	1.0000	100.00
1.5	1,556,510		0.0000	1.0000	100.00
2.5	1,487,728		0.0000	1.0000	100.00
3.5	1,487,728		0.0000	1.0000	100.00
4.5	1,487,728		0.0000	1.0000	100.00
5.5	1,438,802		0.0000	1.0000	100.00
6.5	1,392,166		0.0000	1.0000	100.00
7.5	1,327,312		0.0000	1.0000	100.00
8.5	1,327,312		0.0000	1.0000	100.00
9.5	1,327,312		0.0000	1.0000	100.00
10.5	1,322,416		0.0000	1.0000	100.00
11.5	1,322,416		0.0000	1.0000	100.00
12.5	1,231,910		0.0000	1.0000	100.00
13.5	1,036,964		0.0000	1.0000	100.00
14.5	997,383		0.0000	1.0000	100.00
15.5	832,114		0.0000	1.0000	100.00
16.5	463,684		0.0000	1.0000	100.00
17.5	443,141	274,464	0.6194	0.3806	100.00
18.5	160,031		0.0000	1.0000	38.06
19.5	151,394		0.0000	1.0000	38.06
20.5	149,988		0.0000	1.0000	38.06
21.5	149,988		0.0000	1.0000	38.06
22.5	149,988	61,638	0.4110	0.5890	38.06
23.5	88,349		0.0000	1.0000	22.42
24.5	88,349		0.0000	1.0000	22.42
25.5	88,349	65,278	0.7389	0.2611	22.42
26.5	23,071		0.0000	1.0000	5.86
27.5	23,071		0.0000	1.0000	5.86
28.5	23,071		0.0000	1.0000	5.86
29.5	23,071	887	0.0384	0.9616	5.86
30.5	22,185		0.0000	1.0000	5.63
31.5	22,185		0.0000	1.0000	5.63
32.5	22,185		0.0000	1.0000	5.63
33.5	22,185		0.0000	1.0000	5.63
34.5	22,185	21,127	0.9523	0.0477	5.63
35.5	1,057		0.0000	1.0000	0.27
36.5	1,057		0.0000	1.0000	0.27
37.5	1,057		0.0000	1.0000	0.27
38.5	1,057		0.0000	1.0000	0.27

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 362.00 - DISTRIBUTION - STATION EQUIPMENT

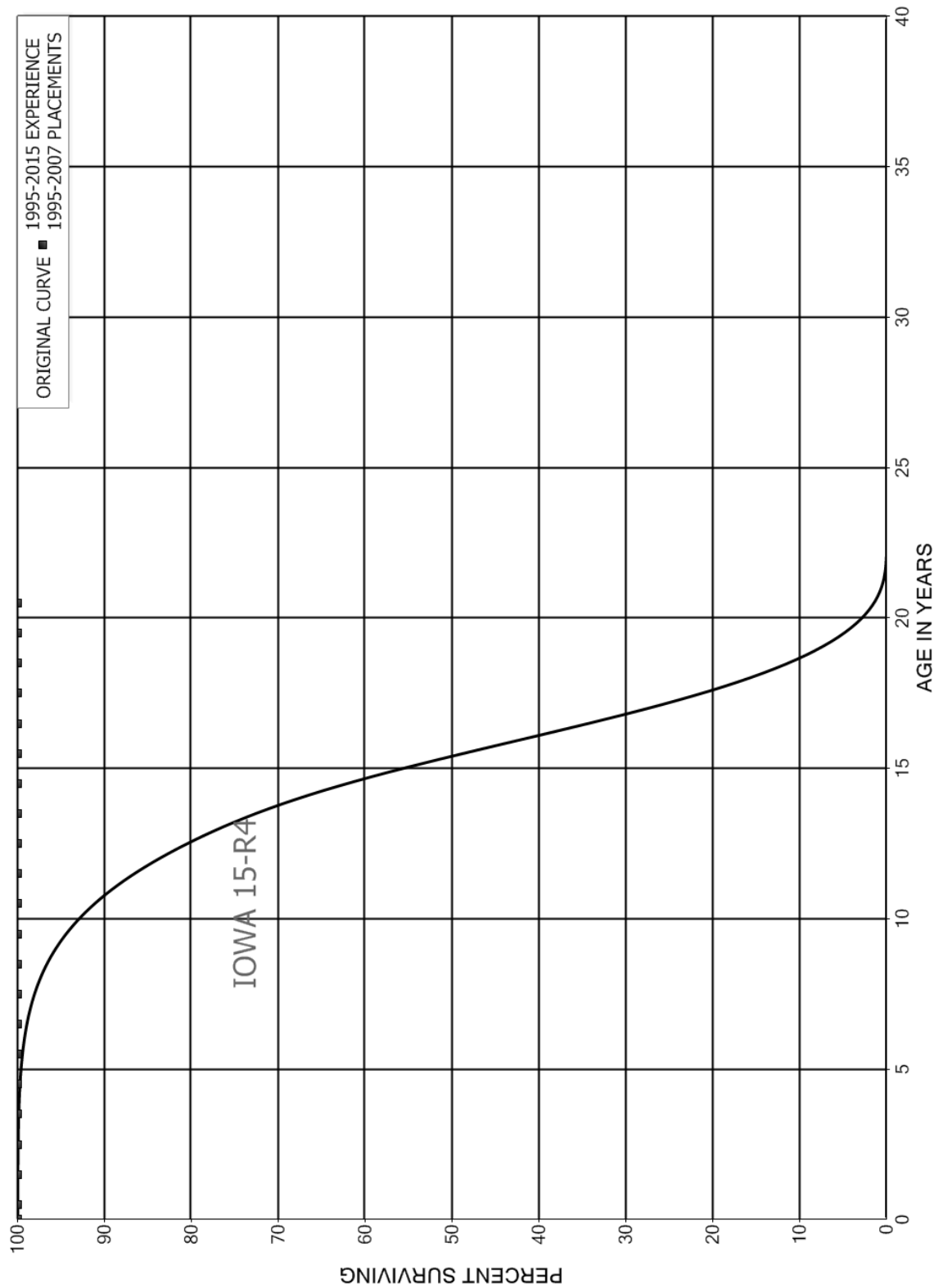
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1961-2014

EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,057		0.0000	1.0000	0.27
40.5	1,057		0.0000	1.0000	0.27
41.5	1,057		0.0000	1.0000	0.27
42.5	1,057		0.0000	1.0000	0.27
43.5	1,057		0.0000	1.0000	0.27
44.5	1,057		0.0000	1.0000	0.27
45.5	1,057		0.0000	1.0000	0.27
46.5	1,057		0.0000	1.0000	0.27
47.5	1,057		0.0000	1.0000	0.27
48.5	1,057		0.0000	1.0000	0.27
49.5	1,057		0.0000	1.0000	0.27
50.5	1,057		0.0000	1.0000	0.27
51.5	1,057		0.0000	1.0000	0.27
52.5	1,057		0.0000	1.0000	0.27
53.5	1,057		0.0000	1.0000	0.27
54.5					0.27

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 363.00 - DISTRIBUTION - STORAGE BATTERY EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 363.00 - DISTRIBUTION - STORAGE BATTERY EQUIPMENT

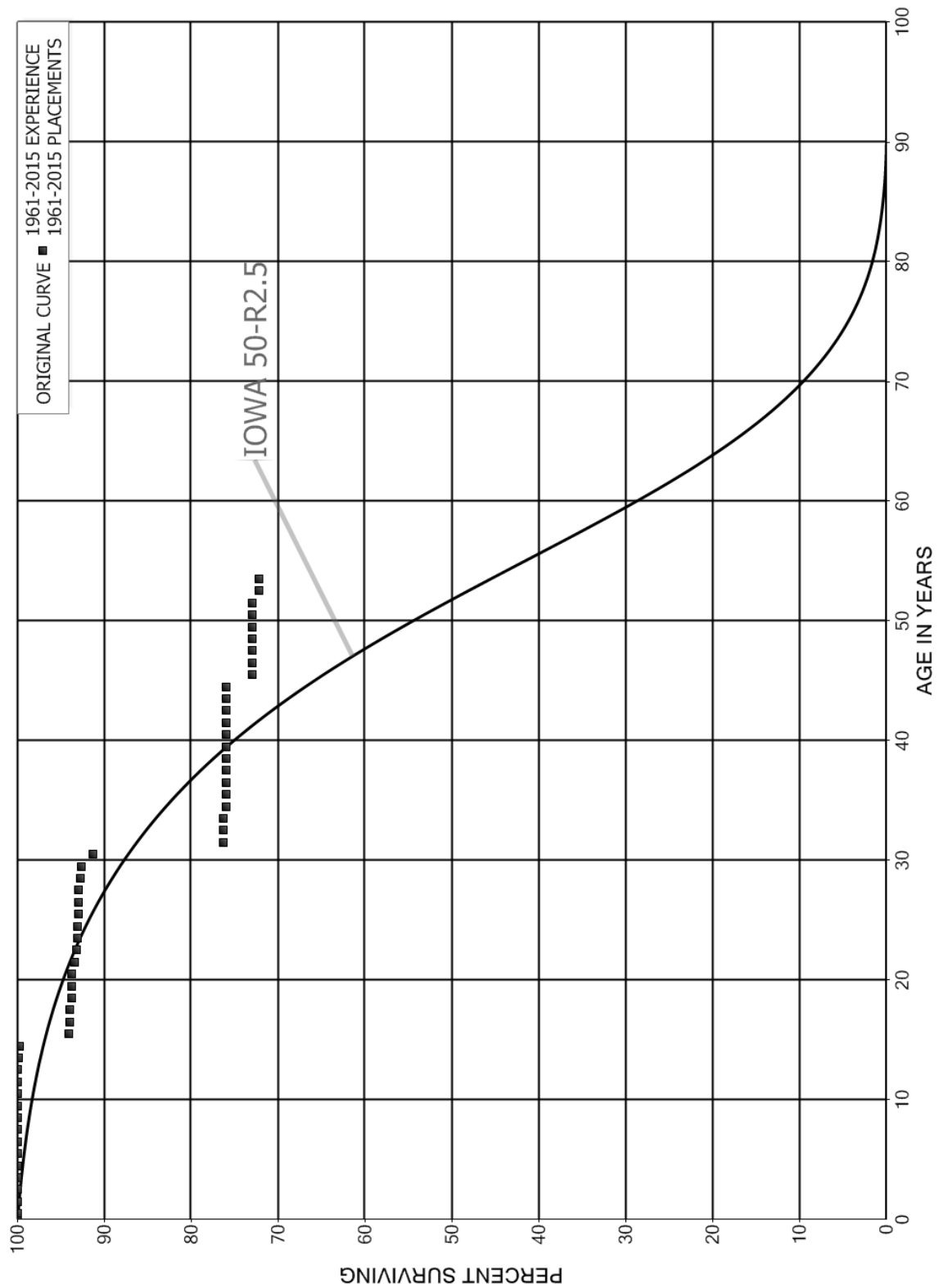
ORIGINAL LIFE TABLE

PLACEMENT BAND 1995-2007

EXPERIENCE BAND 1995-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	73,241		0.0000	1.0000	100.00
0.5	73,241		0.0000	1.0000	100.00
1.5	73,241		0.0000	1.0000	100.00
2.5	73,241		0.0000	1.0000	100.00
3.5	73,241		0.0000	1.0000	100.00
4.5	73,241		0.0000	1.0000	100.00
5.5	73,241		0.0000	1.0000	100.00
6.5	73,241		0.0000	1.0000	100.00
7.5	73,241		0.0000	1.0000	100.00
8.5	34,190		0.0000	1.0000	100.00
9.5	10,960		0.0000	1.0000	100.00
10.5	10,960		0.0000	1.0000	100.00
11.5	10,960		0.0000	1.0000	100.00
12.5	10,960		0.0000	1.0000	100.00
13.5	10,960		0.0000	1.0000	100.00
14.5	10,960		0.0000	1.0000	100.00
15.5	10,960		0.0000	1.0000	100.00
16.5	10,960		0.0000	1.0000	100.00
17.5	10,960		0.0000	1.0000	100.00
18.5	10,960		0.0000	1.0000	100.00
19.5	9,973		0.0000	1.0000	100.00
20.5					100.00

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 364.00 - DISTRIBUTION - POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 364.00 - DISTRIBUTION - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1961-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,807,035		0.0000	1.0000	100.00
0.5	24,690,217		0.0000	1.0000	100.00
1.5	23,500,054	4,642	0.0002	0.9998	100.00
2.5	23,139,885	4,632	0.0002	0.9998	99.98
3.5	23,021,485		0.0000	1.0000	99.96
4.5	22,543,924		0.0000	1.0000	99.96
5.5	22,149,180		0.0000	1.0000	99.96
6.5	21,780,667		0.0000	1.0000	99.96
7.5	21,140,900		0.0000	1.0000	99.96
8.5	20,679,143		0.0000	1.0000	99.96
9.5	20,270,537	3,800	0.0002	0.9998	99.96
10.5	19,774,573		0.0000	1.0000	99.94
11.5	19,770,655	138	0.0000	1.0000	99.94
12.5	19,225,492	26,943	0.0014	0.9986	99.94
13.5	18,862,753	9,746	0.0005	0.9995	99.80
14.5	18,589,729	1,052,394	0.0566	0.9434	99.75
15.5	16,763,302	16,537	0.0010	0.9990	94.10
16.5	15,825,734	14,421	0.0009	0.9991	94.01
17.5	14,797,147	22,912	0.0015	0.9985	93.92
18.5	13,874,491	7,219	0.0005	0.9995	93.78
19.5	12,767,826	4,870	0.0004	0.9996	93.73
20.5	11,518,405	35,486	0.0031	0.9969	93.69
21.5	11,482,920	24,323	0.0021	0.9979	93.41
22.5	11,458,596	16,220	0.0014	0.9986	93.21
23.5	11,442,376	3,057	0.0003	0.9997	93.08
24.5	10,303,444	6,846	0.0007	0.9993	93.05
25.5	10,117,366		0.0000	1.0000	92.99
26.5	9,455,601	9,333	0.0010	0.9990	92.99
27.5	8,746,650	12,258	0.0014	0.9986	92.90
28.5	8,059,368	16,406	0.0020	0.9980	92.77
29.5	7,401,261	102,181	0.0138	0.9862	92.58
30.5	6,781,097	1,114,451	0.1643	0.8357	91.30
31.5	5,376,167		0.0000	1.0000	76.29
32.5	5,053,692	3,955	0.0008	0.9992	76.29
33.5	4,796,596	14,370	0.0030	0.9970	76.24
34.5	4,578,851		0.0000	1.0000	76.01
35.5	4,188,730		0.0000	1.0000	76.01
36.5	3,793,084		0.0000	1.0000	76.01
37.5	3,597,237		0.0000	1.0000	76.01
38.5	3,481,803	2,350	0.0007	0.9993	76.01

NORTHWEST TERRITORIES POWER CORPORATION

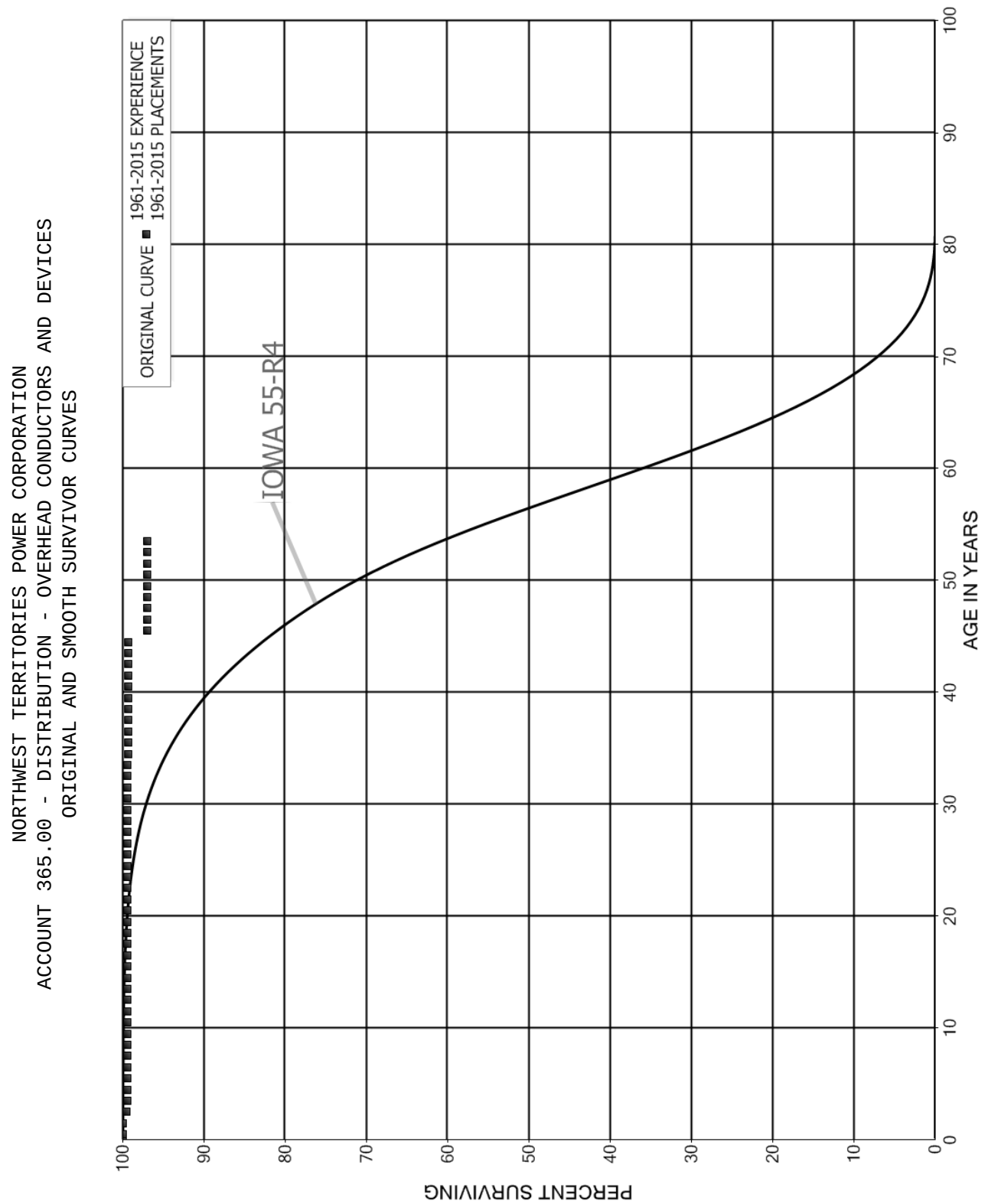
ACCOUNT 364.00 - DISTRIBUTION - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1961-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,098,536		0.0000	1.0000	75.96
40.5	2,440,427		0.0000	1.0000	75.96
41.5	2,045,580	1,011	0.0005	0.9995	75.96
42.5	1,827,842		0.0000	1.0000	75.92
43.5	1,263,103		0.0000	1.0000	75.92
44.5	933,231	36,270	0.0389	0.9611	75.92
45.5	866,417		0.0000	1.0000	72.97
46.5	866,417		0.0000	1.0000	72.97
47.5	848,874		0.0000	1.0000	72.97
48.5	848,874		0.0000	1.0000	72.97
49.5	742,327		0.0000	1.0000	72.97
50.5	742,327		0.0000	1.0000	72.97
51.5	742,027	7,643	0.0103	0.9897	72.97
52.5	692,114		0.0000	1.0000	72.22
53.5	22,247		0.0000	1.0000	72.22
54.5					72.22



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 365.00 - DISTRIBUTION - OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1961-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,017,481		0.0000	1.0000	100.00
0.5	7,474,038		0.0000	1.0000	100.00
1.5	7,161,306	38,896	0.0054	0.9946	100.00
2.5	7,081,387	1,428	0.0002	0.9998	99.46
3.5	7,062,694		0.0000	1.0000	99.44
4.5	6,962,431		0.0000	1.0000	99.44
5.5	6,882,447		0.0000	1.0000	99.44
6.5	6,795,921		0.0000	1.0000	99.44
7.5	6,624,168		0.0000	1.0000	99.44
8.5	6,463,042		0.0000	1.0000	99.44
9.5	6,369,037		0.0000	1.0000	99.44
10.5	6,250,658		0.0000	1.0000	99.44
11.5	6,250,234		0.0000	1.0000	99.44
12.5	6,120,632		0.0000	1.0000	99.44
13.5	6,086,524		0.0000	1.0000	99.44
14.5	6,064,506		0.0000	1.0000	99.44
15.5	5,912,433		0.0000	1.0000	99.44
16.5	5,617,866	454	0.0001	0.9999	99.44
17.5	5,369,026		0.0000	1.0000	99.43
18.5	5,069,807		0.0000	1.0000	99.43
19.5	4,779,157		0.0000	1.0000	99.43
20.5	4,444,085		0.0000	1.0000	99.43
21.5	4,444,085	2,648	0.0006	0.9994	99.43
22.5	4,441,437		0.0000	1.0000	99.37
23.5	4,441,437		0.0000	1.0000	99.37
24.5	4,441,437		0.0000	1.0000	99.37
25.5	4,395,502		0.0000	1.0000	99.37
26.5	4,164,796		0.0000	1.0000	99.37
27.5	3,960,721		0.0000	1.0000	99.37
28.5	3,619,527		0.0000	1.0000	99.37
29.5	3,349,563		0.0000	1.0000	99.37
30.5	3,065,548		0.0000	1.0000	99.37
31.5	2,915,660		0.0000	1.0000	99.37
32.5	2,757,959		0.0000	1.0000	99.37
33.5	2,633,357	2,997	0.0011	0.9989	99.37
34.5	2,528,673		0.0000	1.0000	99.26
35.5	2,327,484		0.0000	1.0000	99.26
36.5	2,121,551		0.0000	1.0000	99.26
37.5	1,977,647		0.0000	1.0000	99.26
38.5	1,926,756		0.0000	1.0000	99.26

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 365.00 - DISTRIBUTION - OVERHEAD CONDUCTORS AND DEVICES

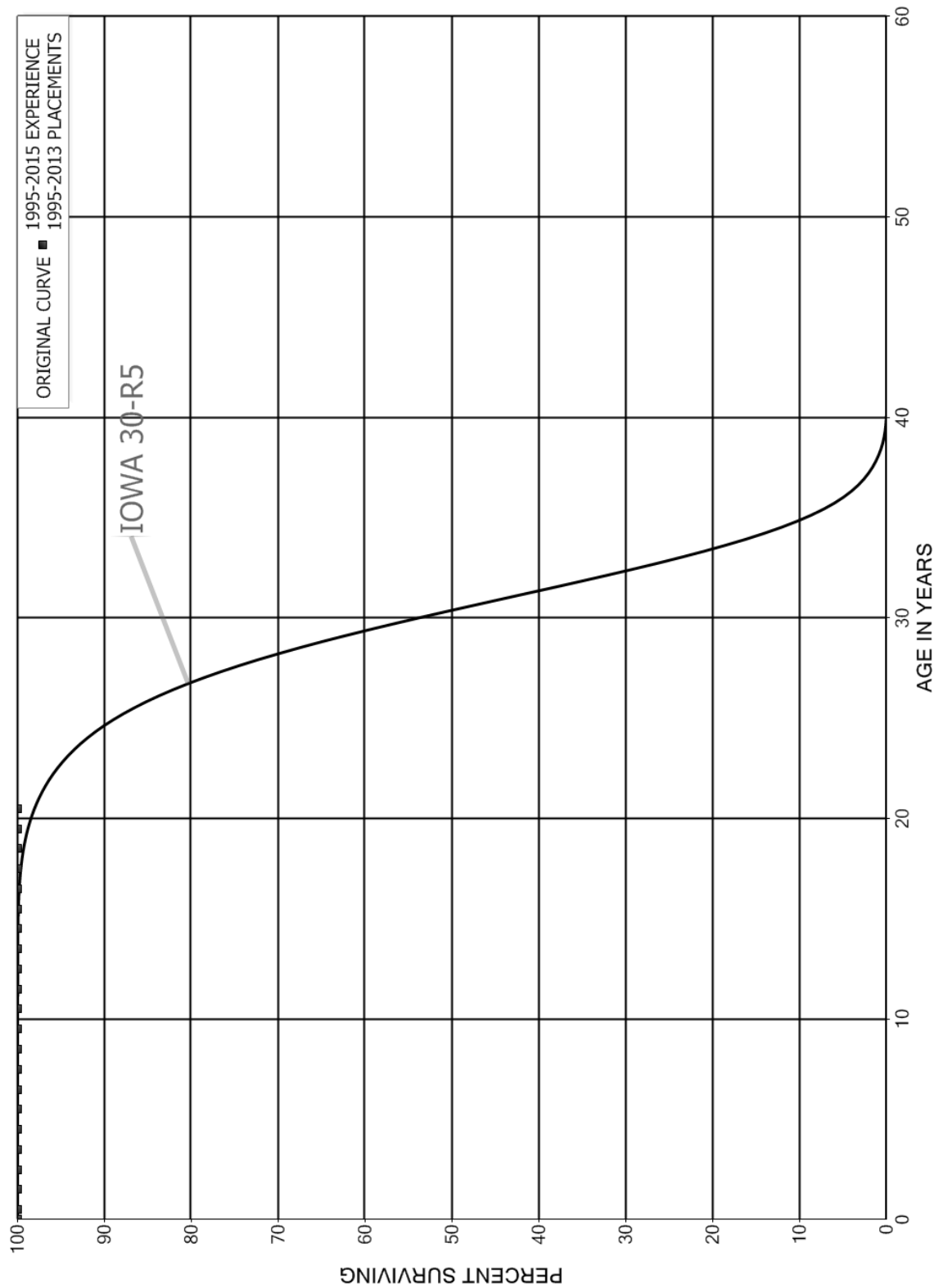
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1961-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,729,251		0.0000	1.0000	99.26
40.5	1,400,197		0.0000	1.0000	99.26
41.5	1,028,576		0.0000	1.0000	99.26
42.5	910,694		0.0000	1.0000	99.26
43.5	628,325		0.0000	1.0000	99.26
44.5	463,389	10,671	0.0230	0.9770	99.26
45.5	438,721		0.0000	1.0000	96.97
46.5	438,721		0.0000	1.0000	96.97
47.5	429,950		0.0000	1.0000	96.97
48.5	429,950		0.0000	1.0000	96.97
49.5	376,676		0.0000	1.0000	96.97
50.5	376,676		0.0000	1.0000	96.97
51.5	376,526		0.0000	1.0000	96.97
52.5	355,391		0.0000	1.0000	96.97
53.5	9,172		0.0000	1.0000	96.97
54.5					96.97

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 366.00 - DISTRIBUTION - UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 366.00 - DISTRIBUTION - UNDERGROUND CONDUIT

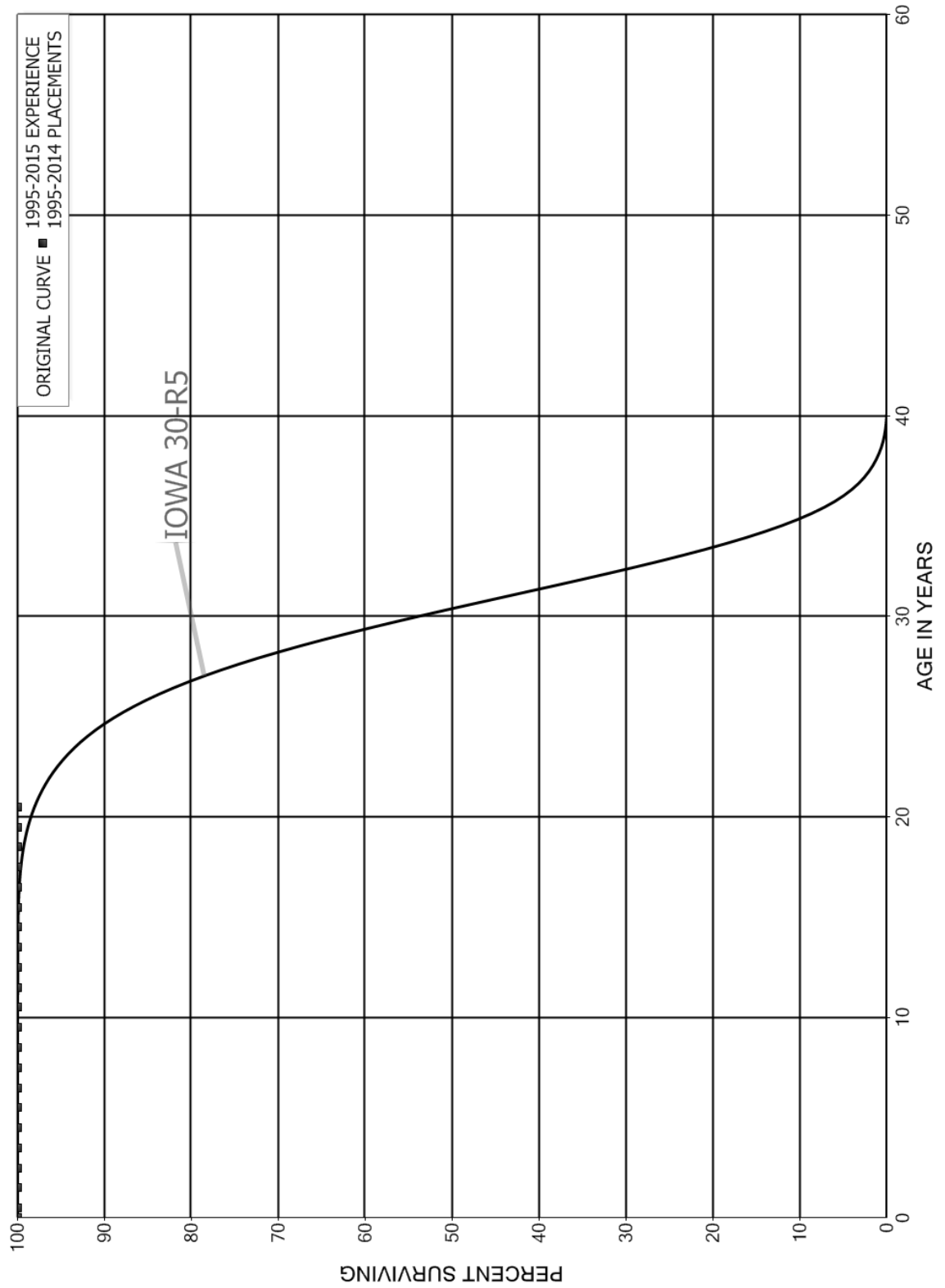
ORIGINAL LIFE TABLE

PLACEMENT BAND 1995-2013

EXPERIENCE BAND 1995-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	147,910		0.0000	1.0000	100.00
0.5	147,910		0.0000	1.0000	100.00
1.5	120,889		0.0000	1.0000	100.00
2.5	66,292		0.0000	1.0000	100.00
3.5	66,292		0.0000	1.0000	100.00
4.5	58,644		0.0000	1.0000	100.00
5.5	58,644		0.0000	1.0000	100.00
6.5	58,644		0.0000	1.0000	100.00
7.5	58,644		0.0000	1.0000	100.00
8.5	58,644		0.0000	1.0000	100.00
9.5	34,799		0.0000	1.0000	100.00
10.5	34,799		0.0000	1.0000	100.00
11.5	34,799		0.0000	1.0000	100.00
12.5	34,799		0.0000	1.0000	100.00
13.5	34,799		0.0000	1.0000	100.00
14.5	34,799		0.0000	1.0000	100.00
15.5	34,799		0.0000	1.0000	100.00
16.5	8,481		0.0000	1.0000	100.00
17.5	8,481		0.0000	1.0000	100.00
18.5	8,481		0.0000	1.0000	100.00
19.5	8,481		0.0000	1.0000	100.00
20.5					100.00

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 367.00 - DISTRIBUTION - UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

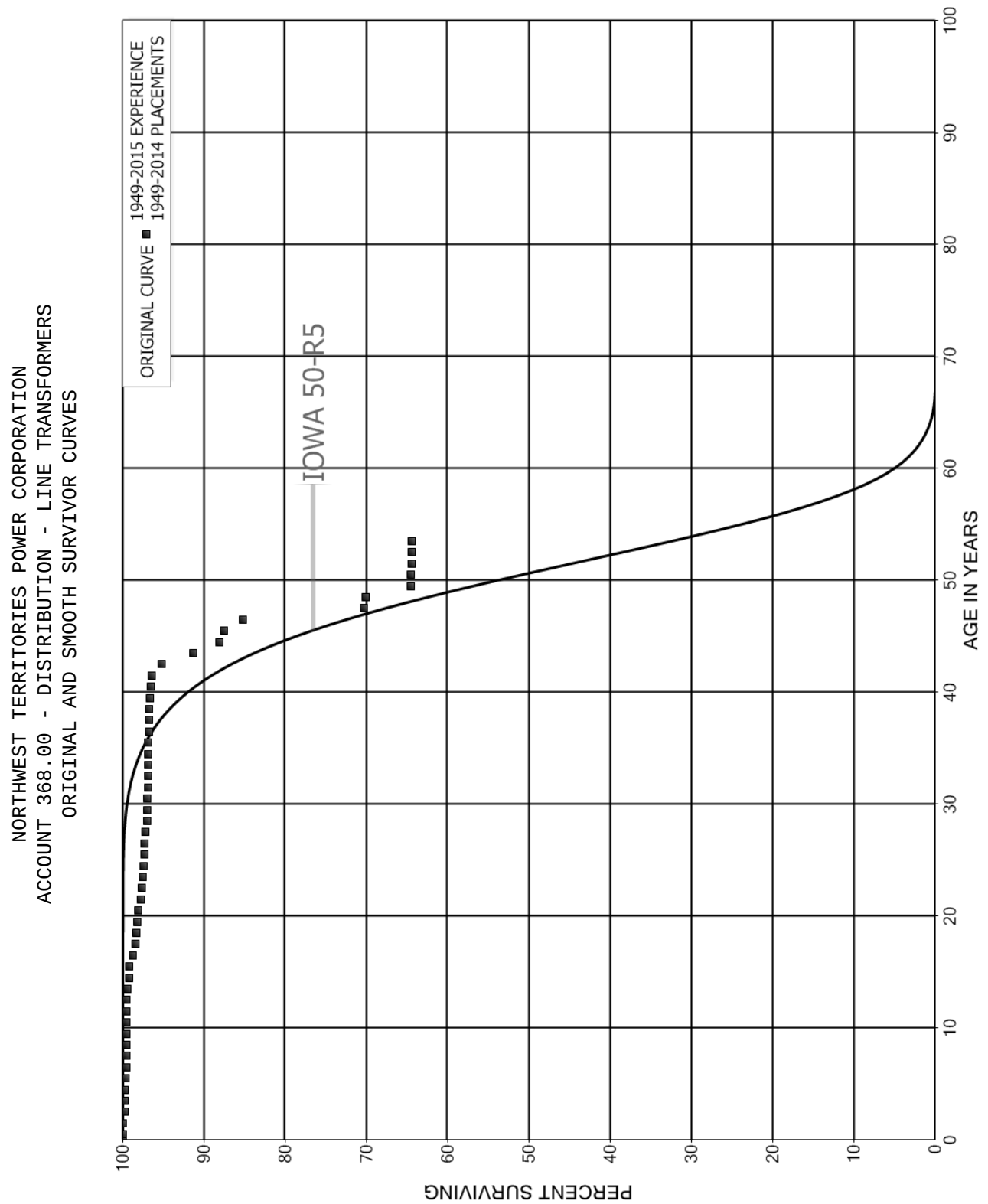
ACCOUNT 367.00 - DISTRIBUTION - UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1995-2014

EXPERIENCE BAND 1995-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	688,695		0.0000	1.0000	100.00
0.5	750,604		0.0000	1.0000	100.00
1.5	449,588		0.0000	1.0000	100.00
2.5	344,519		0.0000	1.0000	100.00
3.5	344,519		0.0000	1.0000	100.00
4.5	272,710		0.0000	1.0000	100.00
5.5	218,743		0.0000	1.0000	100.00
6.5	213,607		0.0000	1.0000	100.00
7.5	181,258		0.0000	1.0000	100.00
8.5	165,659		0.0000	1.0000	100.00
9.5	165,659		0.0000	1.0000	100.00
10.5	165,659		0.0000	1.0000	100.00
11.5	165,659		0.0000	1.0000	100.00
12.5	149,093		0.0000	1.0000	100.00
13.5	149,093		0.0000	1.0000	100.00
14.5	149,093		0.0000	1.0000	100.00
15.5	147,718		0.0000	1.0000	100.00
16.5	38,394		0.0000	1.0000	100.00
17.5	38,394		0.0000	1.0000	100.00
18.5	35,414		0.0000	1.0000	100.00
19.5	34,718		0.0000	1.0000	100.00
20.5					100.00



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 368.00 - DISTRIBUTION - LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2014

EXPERIENCE BAND 1949-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,744,646		0.0000	1.0000	100.00
0.5	7,833,192		0.0000	1.0000	100.00
1.5	7,217,716	19,824	0.0027	0.9973	100.00
2.5	6,485,728		0.0000	1.0000	99.73
3.5	6,274,398		0.0000	1.0000	99.73
4.5	5,934,339	7,046	0.0012	0.9988	99.73
5.5	5,590,732	4,961	0.0009	0.9991	99.61
6.5	5,247,614		0.0000	1.0000	99.52
7.5	5,043,504		0.0000	1.0000	99.52
8.5	4,815,386		0.0000	1.0000	99.52
9.5	4,752,078		0.0000	1.0000	99.52
10.5	4,585,226	403	0.0001	0.9999	99.52
11.5	4,583,725	338	0.0001	0.9999	99.51
12.5	4,462,682	4,046	0.0009	0.9991	99.50
13.5	4,432,668	8,715	0.0020	0.9980	99.41
14.5	4,398,678	1,412	0.0003	0.9997	99.22
15.5	4,012,137	17,076	0.0043	0.9957	99.18
16.5	3,705,109	13,424	0.0036	0.9964	98.76
17.5	3,445,990	3,250	0.0009	0.9991	98.40
18.5	3,181,954	5,090	0.0016	0.9984	98.31
19.5	2,622,491	2,089	0.0008	0.9992	98.15
20.5	2,195,639	6,828	0.0031	0.9969	98.08
21.5	2,188,811	3,069	0.0014	0.9986	97.77
22.5	2,185,742	2,606	0.0012	0.9988	97.63
23.5	2,183,136	3,370	0.0015	0.9985	97.52
24.5	2,179,766	1,183	0.0005	0.9995	97.37
25.5	2,178,583	1,123	0.0005	0.9995	97.31
26.5	1,861,727	1,950	0.0010	0.9990	97.26
27.5	1,846,990	4,013	0.0022	0.9978	97.16
28.5	1,842,977	628	0.0003	0.9997	96.95
29.5	1,797,067		0.0000	1.0000	96.92
30.5	1,742,528	1,462	0.0008	0.9992	96.92
31.5	1,741,065		0.0000	1.0000	96.84
32.5	1,741,065		0.0000	1.0000	96.84
33.5	1,731,110		0.0000	1.0000	96.84
34.5	1,731,110	309	0.0002	0.9998	96.84
35.5	1,714,823	1,035	0.0006	0.9994	96.82
36.5	1,677,860		0.0000	1.0000	96.76
37.5	1,457,436	1,320	0.0009	0.9991	96.76
38.5	1,156,537	1,107	0.0010	0.9990	96.67

NORTHWEST TERRITORIES POWER CORPORATION

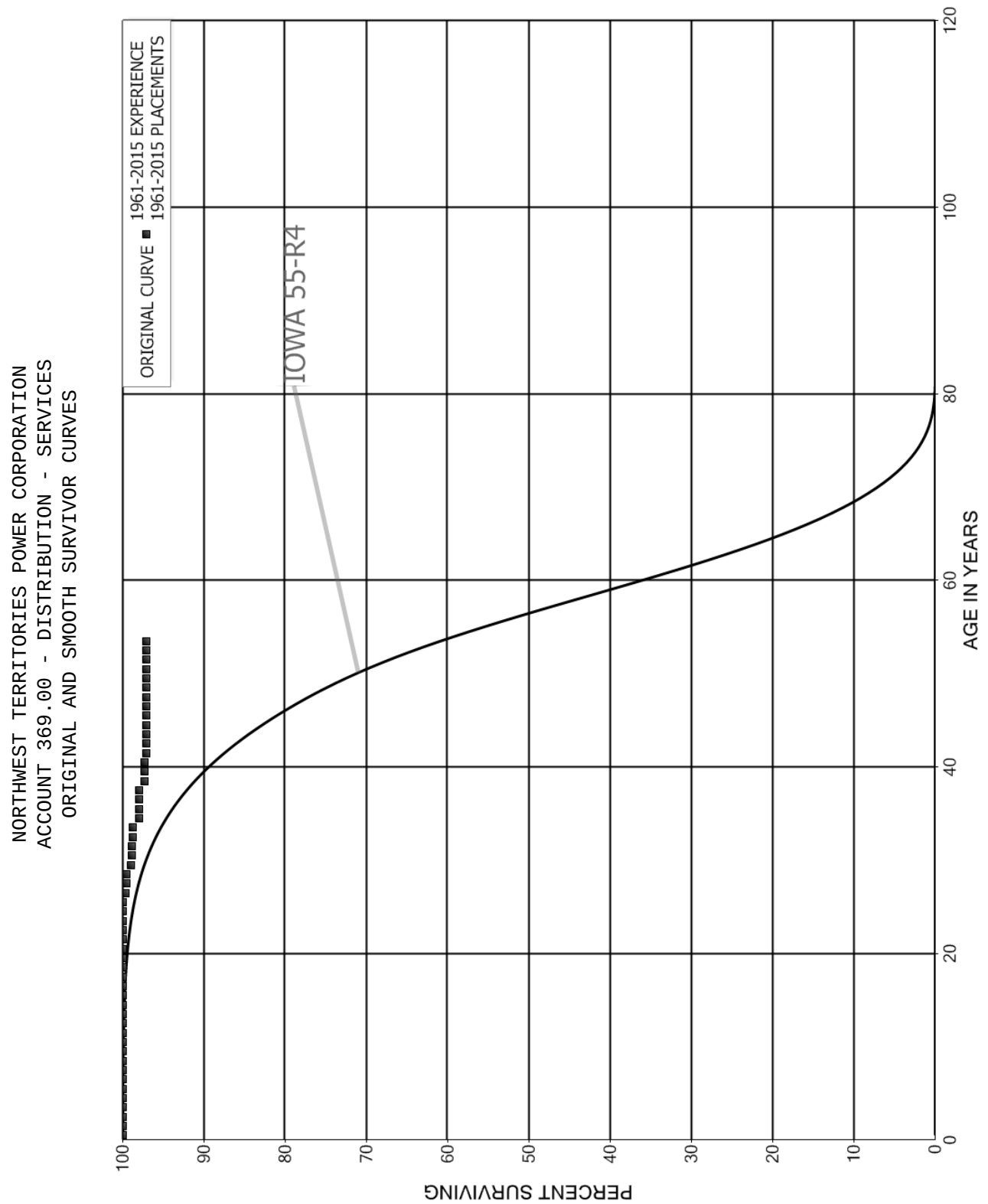
ACCOUNT 368.00 - DISTRIBUTION - LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2014

EXPERIENCE BAND 1949-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,042,532	524	0.0005	0.9995	96.58
40.5	927,585	1,148	0.0012	0.9988	96.53
41.5	832,329	10,396	0.0125	0.9875	96.41
42.5	452,946	18,581	0.0410	0.9590	95.21
43.5	399,557	14,042	0.0351	0.9649	91.30
44.5	311,034	2,170	0.0070	0.9930	88.09
45.5	287,481	7,600	0.0264	0.9736	87.48
46.5	254,564	44,536	0.1749	0.8251	85.17
47.5	198,913	610	0.0031	0.9969	70.27
48.5	174,015	13,666	0.0785	0.9215	70.05
49.5	147,738		0.0000	1.0000	64.55
50.5	147,341	422	0.0029	0.9971	64.55
51.5	142,255		0.0000	1.0000	64.37
52.5	140,521		0.0000	1.0000	64.37
53.5	23,564		0.0000	1.0000	64.37
54.5					64.37



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 369.00 - DISTRIBUTION - SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1961-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,410,295		0.0000	1.0000	100.00
0.5	3,429,376		0.0000	1.0000	100.00
1.5	3,327,075	1,187	0.0004	0.9996	100.00
2.5	3,173,157		0.0000	1.0000	99.96
3.5	3,092,767		0.0000	1.0000	99.96
4.5	2,610,912		0.0000	1.0000	99.96
5.5	2,491,902		0.0000	1.0000	99.96
6.5	2,451,874		0.0000	1.0000	99.96
7.5	2,442,800		0.0000	1.0000	99.96
8.5	2,432,744		0.0000	1.0000	99.96
9.5	2,431,796		0.0000	1.0000	99.96
10.5	2,424,878		0.0000	1.0000	99.96
11.5	2,424,878		0.0000	1.0000	99.96
12.5	2,416,729		0.0000	1.0000	99.96
13.5	2,413,551		0.0000	1.0000	99.96
14.5	2,398,179		0.0000	1.0000	99.96
15.5	2,383,516		0.0000	1.0000	99.96
16.5	2,383,516		0.0000	1.0000	99.96
17.5	2,373,116	657	0.0003	0.9997	99.96
18.5	2,365,399		0.0000	1.0000	99.94
19.5	2,365,314		0.0000	1.0000	99.94
20.5	2,365,314		0.0000	1.0000	99.94
21.5	2,365,314	883	0.0004	0.9996	99.94
22.5	2,320,818		0.0000	1.0000	99.90
23.5	2,154,826		0.0000	1.0000	99.90
24.5	1,698,324		0.0000	1.0000	99.90
25.5	1,697,950	5,175	0.0030	0.9970	99.90
26.5	1,473,331	1,807	0.0012	0.9988	99.59
27.5	1,317,650		0.0000	1.0000	99.47
28.5	1,187,308	6,518	0.0055	0.9945	99.47
29.5	1,095,977	425	0.0004	0.9996	98.93
30.5	946,586		0.0000	1.0000	98.89
31.5	893,789	1,239	0.0014	0.9986	98.89
32.5	846,501		0.0000	1.0000	98.75
33.5	804,311	6,163	0.0077	0.9923	98.75
34.5	764,253		0.0000	1.0000	97.99
35.5	698,428		0.0000	1.0000	97.99
36.5	629,784		0.0000	1.0000	97.99
37.5	596,633	4,557	0.0076	0.9924	97.99
38.5	575,112		0.0000	1.0000	97.25

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 369.00 - DISTRIBUTION - SERVICES

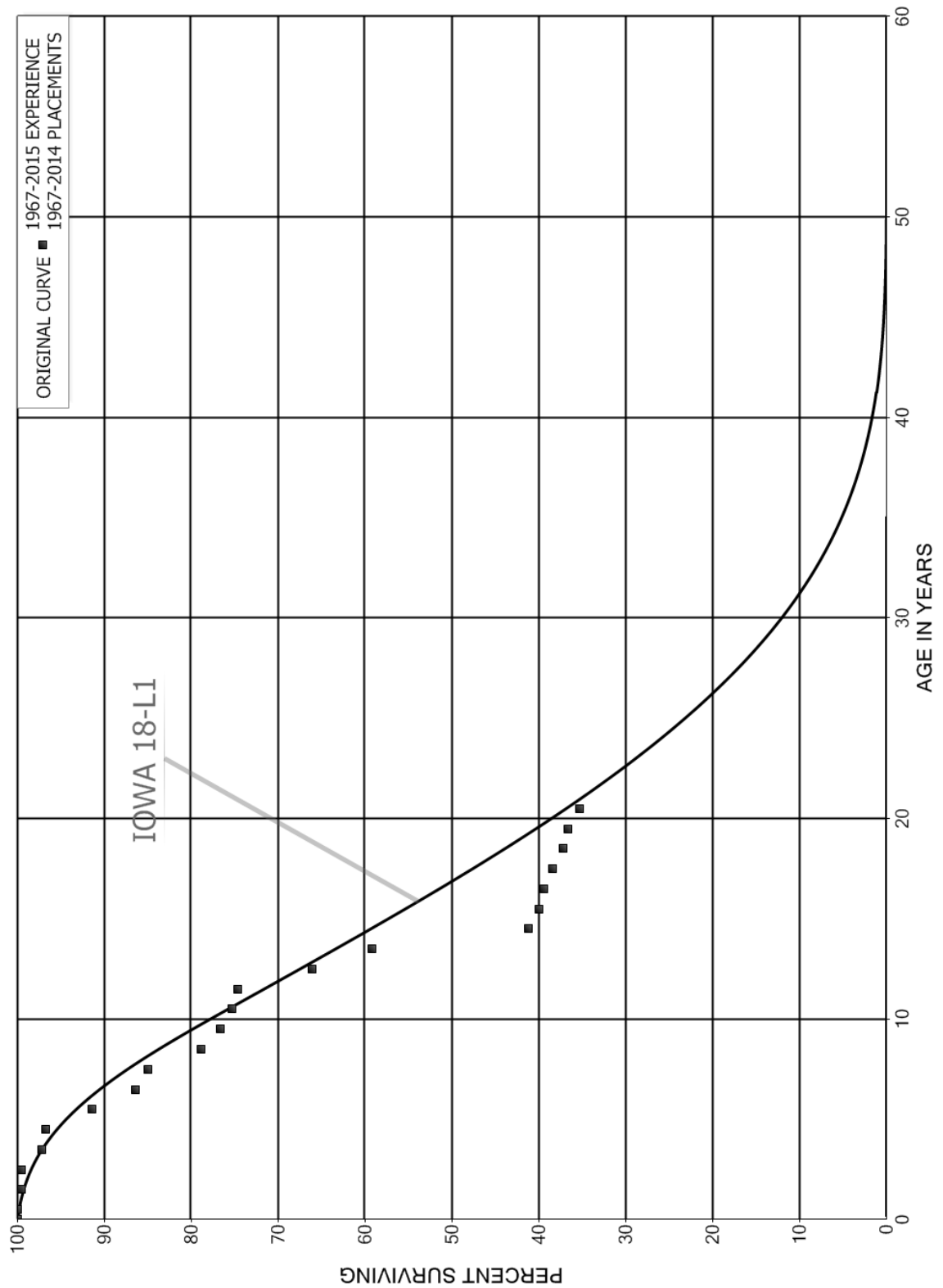
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1961-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	515,440	951	0.0000	1.0000	97.25
40.5	408,276		0.0023	0.9977	97.25
41.5	341,420		0.0000	1.0000	97.02
42.5	302,936		0.0000	1.0000	97.02
43.5	208,813		0.0000	1.0000	97.02
44.5	154,785		0.0000	1.0000	97.02
45.5	149,694		0.0000	1.0000	97.02
46.5	149,694		0.0000	1.0000	97.02
47.5	146,770		0.0000	1.0000	97.02
48.5	146,770		0.0000	1.0000	97.02
49.5	129,013		0.0000	1.0000	97.02
50.5	129,013		0.0000	1.0000	97.02
51.5	128,963		0.0000	1.0000	97.02
52.5	121,918		0.0000	1.0000	97.02
53.5	2,954		0.0000	1.0000	97.02
54.5					97.02

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 370.00 - DISTRIBUTION - METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 370.00 - DISTRIBUTION - METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2014

EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,288,159	1,315	0.0006	0.9994	100.00
0.5	3,961,409	17,615	0.0044	0.9956	99.94
1.5	3,842,465		0.0000	1.0000	99.50
2.5	2,920,875	69,052	0.0236	0.9764	99.50
3.5	2,739,854	12,721	0.0046	0.9954	97.15
4.5	2,609,510	142,724	0.0547	0.9453	96.69
5.5	2,366,199	130,287	0.0551	0.9449	91.41
6.5	2,181,706	36,544	0.0168	0.9832	86.37
7.5	2,088,793	149,187	0.0714	0.9286	84.93
8.5	1,893,481	53,986	0.0285	0.9715	78.86
9.5	1,805,914	30,397	0.0168	0.9832	76.61
10.5	1,703,879	15,935	0.0094	0.9906	75.32
11.5	1,666,058	191,278	0.1148	0.8852	74.62
12.5	1,366,340	142,249	0.1041	0.8959	66.05
13.5	1,236,872	375,663	0.3037	0.6963	59.17
14.5	716,686	21,352	0.0298	0.9702	41.20
15.5	723,308	9,809	0.0136	0.9864	39.97
16.5	672,237	17,687	0.0263	0.9737	39.43
17.5	638,377	20,827	0.0326	0.9674	38.40
18.5	649,937	8,464	0.0130	0.9870	37.14
19.5	627,013	23,435	0.0374	0.9626	36.66
20.5	576,162	1,347	0.0023	0.9977	35.29
21.5	574,815	24,105	0.0419	0.9581	35.21
22.5	550,710		0.0000	1.0000	33.73
23.5	548,105		0.0000	1.0000	33.73
24.5	547,964		0.0000	1.0000	33.73
25.5	547,964	2,923	0.0053	0.9947	33.73
26.5	545,041		0.0000	1.0000	33.55
27.5	545,041		0.0000	1.0000	33.55
28.5	545,185	549	0.0010	0.9990	33.55
29.5	544,636	98,326	0.1805	0.8195	33.52
30.5	446,310	105,280	0.2359	0.7641	27.47
31.5	341,030	36,958	0.1084	0.8916	20.99
32.5	300,440	53,320	0.1775	0.8225	18.71
33.5	239,156	25,868	0.1082	0.8918	15.39
34.5	154,613	29,076	0.1881	0.8119	13.73
35.5	125,537	44,450	0.3541	0.6459	11.15
36.5	81,087	50,887	0.6276	0.3724	7.20
37.5	18,383	11,567	0.6292	0.3708	2.68
38.5	6,816	1,543	0.2264	0.7736	0.99

NORTHWEST TERRITORIES POWER CORPORATION

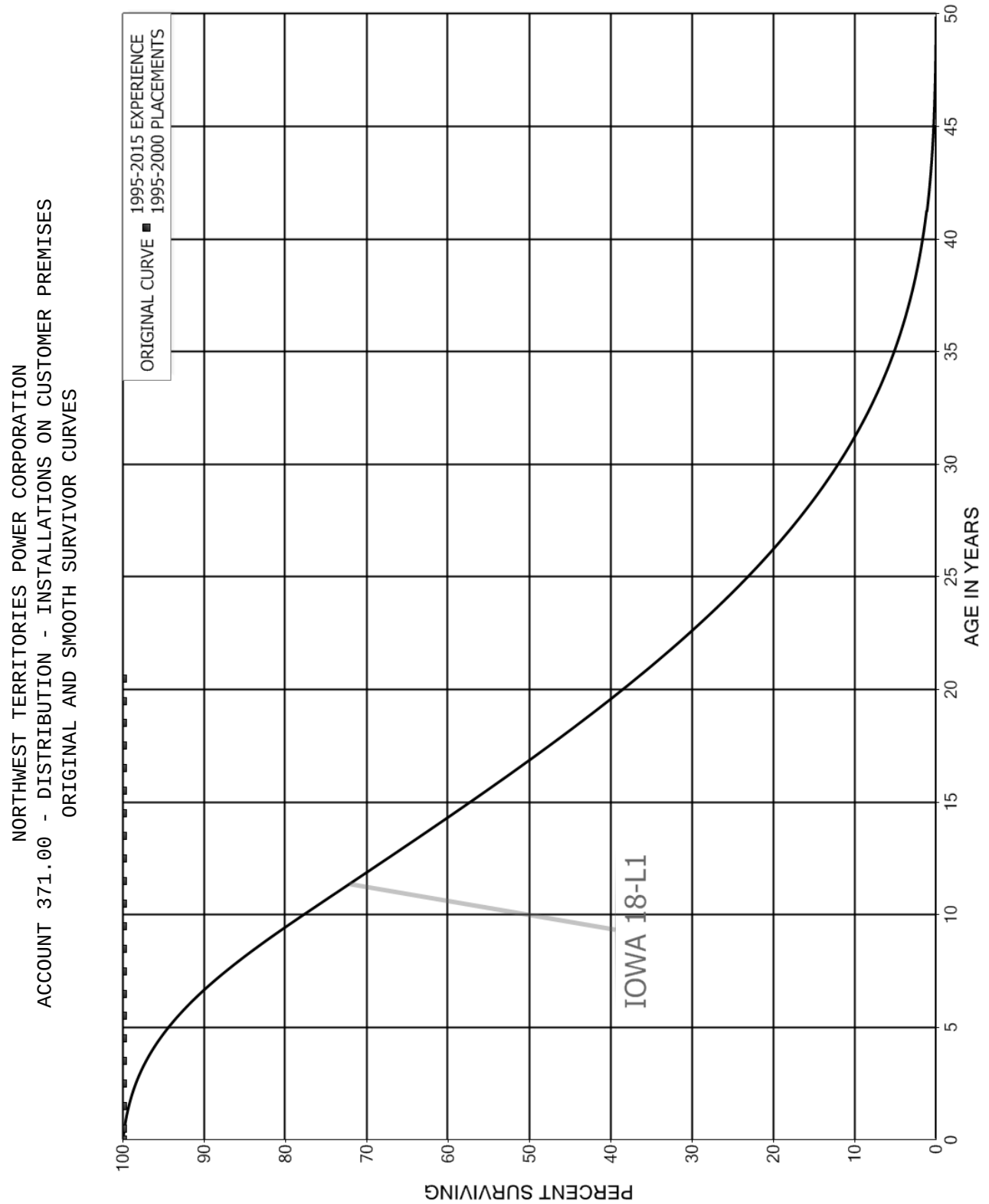
ACCOUNT 370.00 - DISTRIBUTION - METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2014

EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	145		0.0000	1.0000	0.77
40.5	145		0.0000	1.0000	0.77
41.5	145		0.0000	1.0000	0.77
42.5	145		0.0000	1.0000	0.77
43.5	145		0.0000	1.0000	0.77
44.5	145		0.0000	1.0000	0.77
45.5	145		0.0000	1.0000	0.77
46.5	145		0.0000	1.0000	0.77
47.5	145		0.0000	1.0000	0.77
48.5					0.77



NORTHWEST TERRITORIES POWER CORPORATION

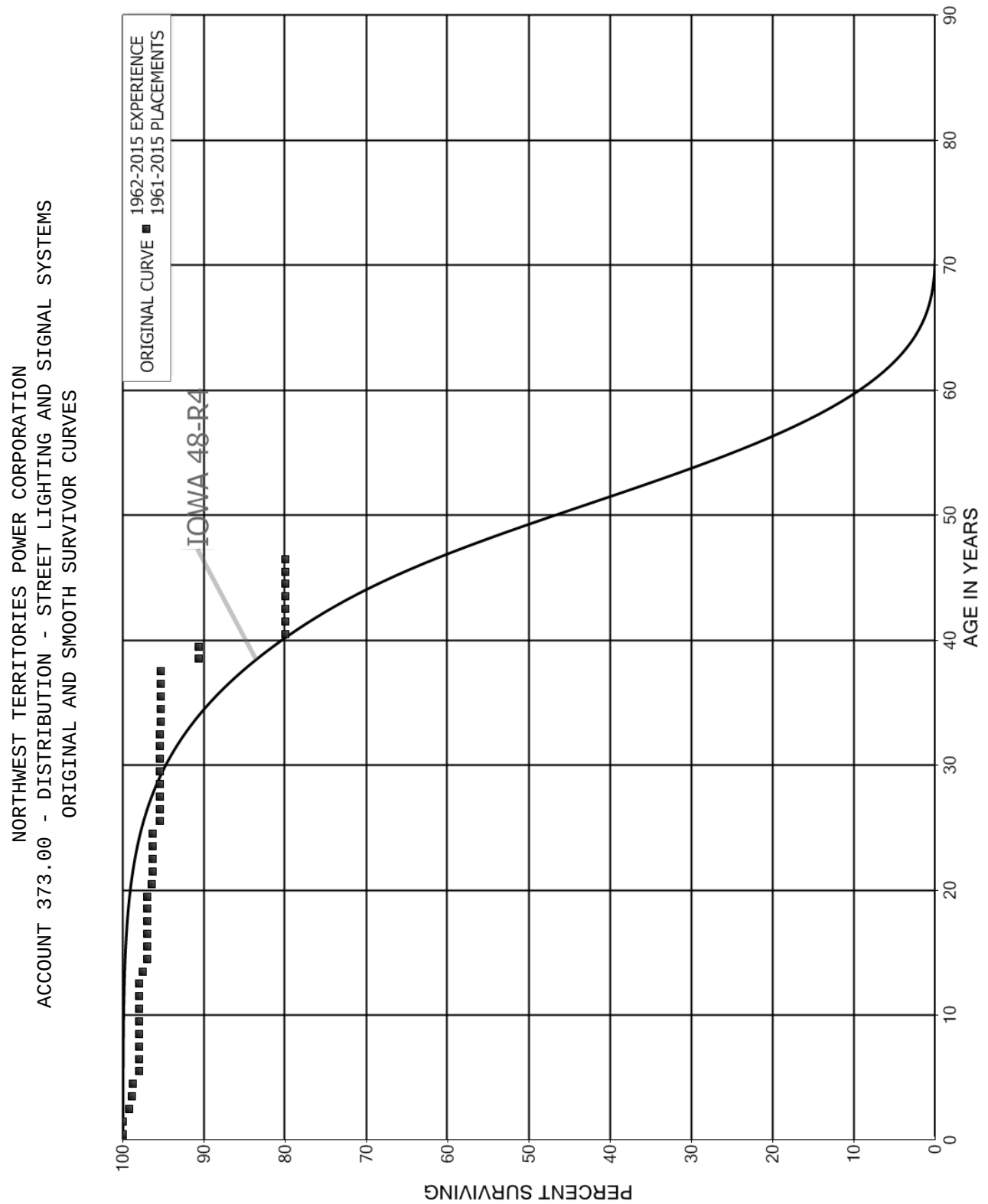
ACCOUNT 371.00 - DISTRIBUTION - INSTALLATIONS ON CUSTOMER PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1995-2000

EXPERIENCE BAND 1995-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	33,890		0.0000	1.0000	100.00
0.5	33,890		0.0000	1.0000	100.00
1.5	33,890		0.0000	1.0000	100.00
2.5	33,890		0.0000	1.0000	100.00
3.5	33,890		0.0000	1.0000	100.00
4.5	33,890		0.0000	1.0000	100.00
5.5	33,890		0.0000	1.0000	100.00
6.5	33,890		0.0000	1.0000	100.00
7.5	33,890		0.0000	1.0000	100.00
8.5	33,890		0.0000	1.0000	100.00
9.5	33,890		0.0000	1.0000	100.00
10.5	33,890		0.0000	1.0000	100.00
11.5	33,890		0.0000	1.0000	100.00
12.5	33,890		0.0000	1.0000	100.00
13.5	33,890		0.0000	1.0000	100.00
14.5	33,890		0.0000	1.0000	100.00
15.5	15,250		0.0000	1.0000	100.00
16.5	15,250		0.0000	1.0000	100.00
17.5	15,250		0.0000	1.0000	100.00
18.5	15,250		0.0000	1.0000	100.00
19.5	7,226		0.0000	1.0000	100.00
20.5					100.00



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 373.00 - DISTRIBUTION - STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,629,049		0.0000	1.0000	100.00
0.5	1,552,385		0.0000	1.0000	100.00
1.5	1,152,872	9,025	0.0078	0.9922	100.00
2.5	996,455	3,493	0.0035	0.9965	99.22
3.5	992,961	1,676	0.0017	0.9983	98.87
4.5	960,376	6,894	0.0072	0.9928	98.70
5.5	896,760		0.0000	1.0000	97.99
6.5	758,636		0.0000	1.0000	97.99
7.5	685,024		0.0000	1.0000	97.99
8.5	604,400	600	0.0010	0.9990	97.99
9.5	603,120		0.0000	1.0000	97.90
10.5	451,828		0.0000	1.0000	97.90
11.5	451,828		0.0000	1.0000	97.90
12.5	451,828	1,778	0.0039	0.9961	97.90
13.5	450,051	2,708	0.0060	0.9940	97.51
14.5	445,145		0.0000	1.0000	96.92
15.5	432,379		0.0000	1.0000	96.92
16.5	417,628		0.0000	1.0000	96.92
17.5	360,429		0.0000	1.0000	96.92
18.5	348,100		0.0000	1.0000	96.92
19.5	310,794	1,855	0.0060	0.9940	96.92
20.5	308,939	188	0.0006	0.9994	96.35
21.5	308,751	141	0.0005	0.9995	96.29
22.5	308,610		0.0000	1.0000	96.24
23.5	308,610		0.0000	1.0000	96.24
24.5	308,610	2,604	0.0084	0.9916	96.24
25.5	306,006		0.0000	1.0000	95.43
26.5	280,801		0.0000	1.0000	95.43
27.5	253,412	139	0.0005	0.9995	95.43
28.5	253,272		0.0000	1.0000	95.38
29.5	223,765		0.0000	1.0000	95.38
30.5	162,221		0.0000	1.0000	95.38
31.5	149,850		0.0000	1.0000	95.38
32.5	149,850	108	0.0007	0.9993	95.38
33.5	149,289		0.0000	1.0000	95.31
34.5	149,289		0.0000	1.0000	95.31
35.5	127,628		0.0000	1.0000	95.31
36.5	114,766		0.0000	1.0000	95.31
37.5	111,989	5,542	0.0495	0.9505	95.31
38.5	106,447		0.0000	1.0000	90.59

NORTHWEST TERRITORIES POWER CORPORATION

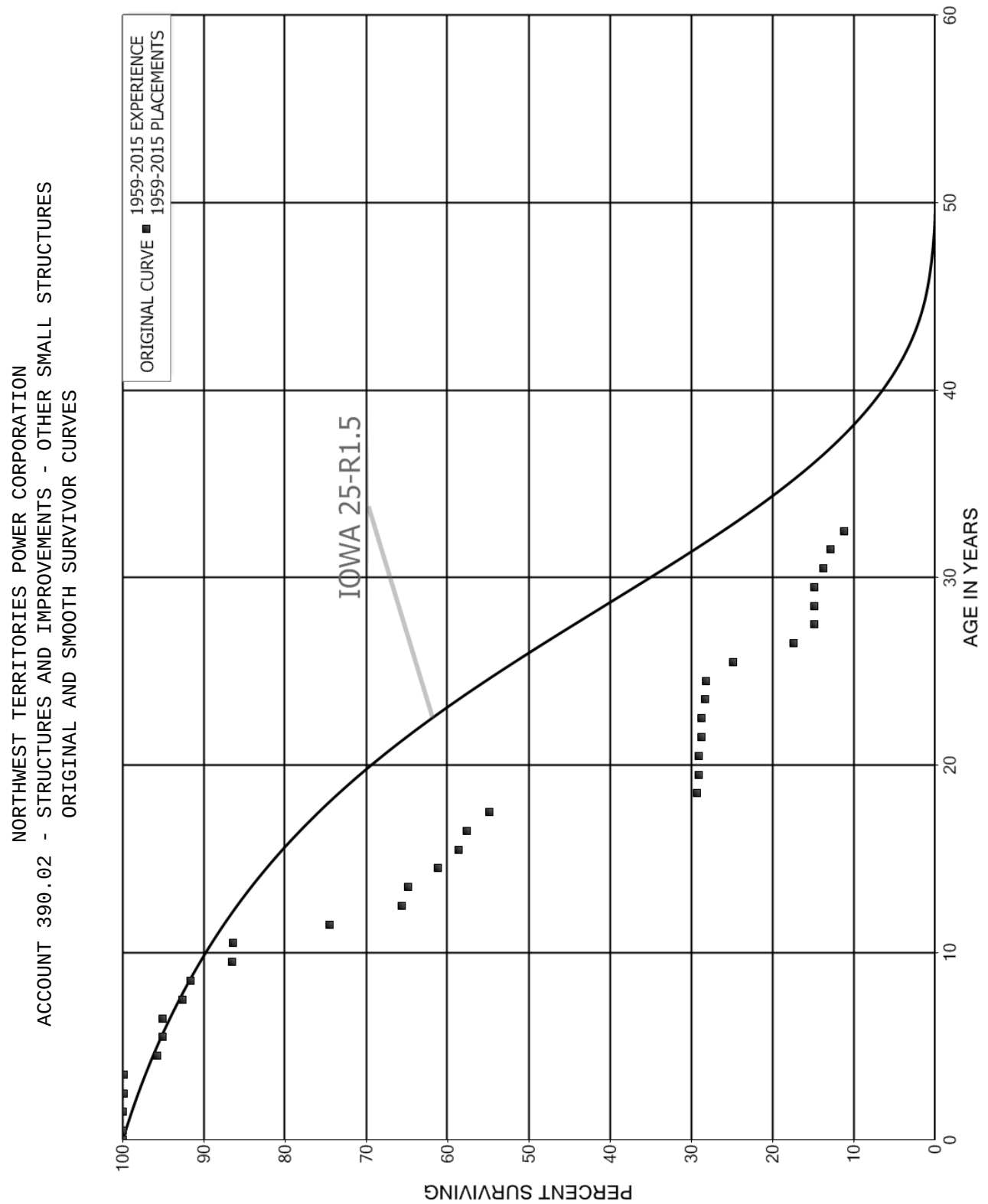
ACCOUNT 373.00 - DISTRIBUTION - STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1961-2015

EXPERIENCE BAND 1962-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	73,800	8,638	0.1170	0.8830	90.59
40.5	58,901		0.0000	1.0000	79.99
41.5	48,551		0.0000	1.0000	79.99
42.5	37,785		0.0000	1.0000	79.99
43.5	28,631		0.0000	1.0000	79.99
44.5	24,487		0.0000	1.0000	79.99
45.5	24,487		0.0000	1.0000	79.99
46.5	19,204		0.0000	1.0000	79.99
47.5	1,933		0.0000	1.0000	79.99
48.5	1,933		0.0000	1.0000	79.99
49.5	308		0.0000	1.0000	79.99
50.5	308		0.0000	1.0000	79.99
51.5	308		0.0000	1.0000	79.99
52.5	308		0.0000	1.0000	79.99
53.5	308		0.0000	1.0000	79.99
54.5					79.99



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 390.02 - STRUCTURES AND IMPROVEMENTS - OTHER SMALL STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2015

EXPERIENCE BAND 1959-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,838,754		0.0000	1.0000	100.00
0.5	22,553,268	20,000	0.0009	0.9991	100.00
1.5	21,804,905	12,932	0.0006	0.9994	99.91
2.5	19,136,320		0.0000	1.0000	99.85
3.5	19,136,320	797,997	0.0417	0.9583	99.85
4.5	14,495,585	98,955	0.0068	0.9932	95.69
5.5	10,508,482		0.0000	1.0000	95.03
6.5	10,059,057	250,800	0.0249	0.9751	95.03
7.5	8,656,753	102,624	0.0119	0.9881	92.67
8.5	8,554,129	475,800	0.0556	0.9444	91.57
9.5	7,945,720	4,222	0.0005	0.9995	86.47
10.5	7,393,678	1,017,810	0.1377	0.8623	86.43
11.5	6,334,035	753,831	0.1190	0.8810	74.53
12.5	5,222,473	66,451	0.0127	0.9873	65.66
13.5	4,876,572	277,801	0.0570	0.9430	64.82
14.5	4,539,932	187,344	0.0413	0.9587	61.13
15.5	3,947,590	66,972	0.0170	0.9830	58.61
16.5	2,966,095	144,323	0.0487	0.9513	57.61
17.5	2,222,275	1,036,317	0.4663	0.5337	54.81
18.5	841,932	3,833	0.0046	0.9954	29.25
19.5	640,981	1,804	0.0028	0.9972	29.12
20.5	639,178	7,630	0.0119	0.9881	29.04
21.5	631,548		0.0000	1.0000	28.69
22.5	631,548	9,583	0.0152	0.9848	28.69
23.5	621,965	2,154	0.0035	0.9965	28.25
24.5	619,811	73,361	0.1184	0.8816	28.16
25.5	483,109	145,470	0.3011	0.6989	24.82
26.5	337,639	48,369	0.1433	0.8567	17.35
27.5	289,270		0.0000	1.0000	14.86
28.5	289,270		0.0000	1.0000	14.86
29.5	289,270	22,350	0.0773	0.9227	14.86
30.5	266,920	16,336	0.0612	0.9388	13.72
31.5	250,584	32,757	0.1307	0.8693	12.88
32.5	217,827	82,825	0.3802	0.6198	11.19
33.5	135,002		0.0000	1.0000	6.94
34.5	135,002		0.0000	1.0000	6.94
35.5	135,002		0.0000	1.0000	6.94
36.5	135,002	21,613	0.1601	0.8399	6.94
37.5	113,389	62,815	0.5540	0.4460	5.83
38.5	50,574	26,311	0.5202	0.4798	2.60

NORTHWEST TERRITORIES POWER CORPORATION

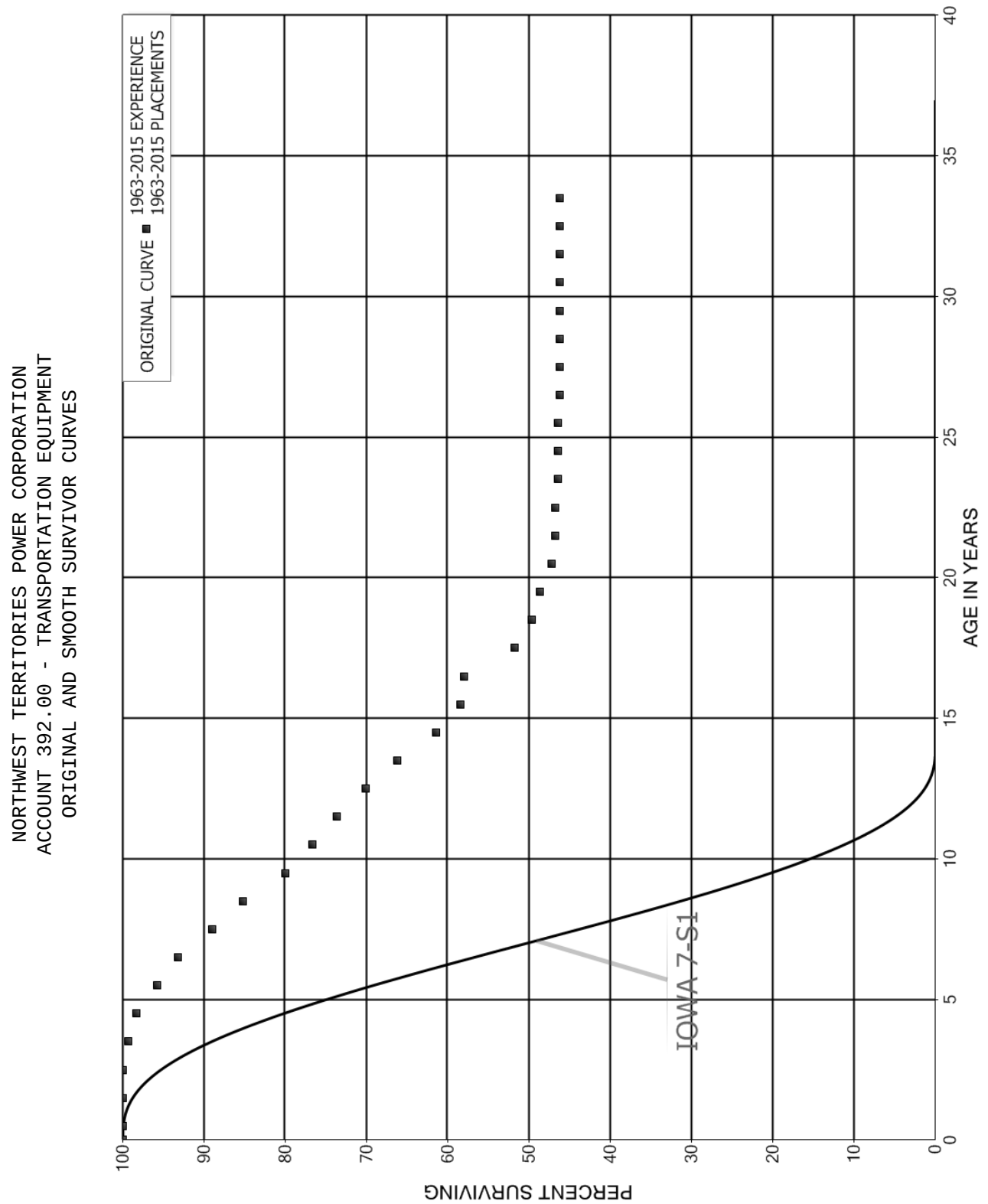
ACCOUNT 390.02 - STRUCTURES AND IMPROVEMENTS - OTHER SMALL STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2015

EXPERIENCE BAND 1959-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	24,263		0.0000	1.0000	1.25
40.5	24,263	19,116	0.7879	0.2121	1.25
41.5	5,147		0.0000	1.0000	0.26
42.5	5,147		0.0000	1.0000	0.26
43.5	5,147		0.0000	1.0000	0.26
44.5	5,147		0.0000	1.0000	0.26
45.5	5,147	5,147	1.0000		0.26
46.5					



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 392.00 - TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2015

EXPERIENCE BAND 1963-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,978,411		0.0000	1.0000	100.00
0.5	8,850,111		0.0000	1.0000	100.00
1.5	8,619,820	2,673	0.0003	0.9997	100.00
2.5	8,349,098	53,567	0.0064	0.9936	99.97
3.5	8,084,010	85,853	0.0106	0.9894	99.33
4.5	7,842,803	199,319	0.0254	0.9746	98.27
5.5	7,323,620	195,273	0.0267	0.9733	95.78
6.5	6,762,782	309,642	0.0458	0.9542	93.22
7.5	6,099,424	262,067	0.0430	0.9570	88.95
8.5	5,471,333	330,379	0.0604	0.9396	85.13
9.5	5,056,569	211,783	0.0419	0.9581	79.99
10.5	4,755,984	184,369	0.0388	0.9612	76.64
11.5	4,571,614	223,574	0.0489	0.9511	73.67
12.5	4,282,872	235,835	0.0551	0.9449	70.07
13.5	3,789,567	272,591	0.0719	0.9281	66.21
14.5	3,512,362	174,679	0.0497	0.9503	61.45
15.5	3,293,118	22,773	0.0069	0.9931	58.39
16.5	2,864,987	306,703	0.1071	0.8929	57.99
17.5	2,226,929	90,702	0.0407	0.9593	51.78
18.5	1,927,872	41,947	0.0218	0.9782	49.67
19.5	1,782,577	52,501	0.0295	0.9705	48.59
20.5	1,473,134	12,088	0.0082	0.9918	47.16
21.5	1,461,046		0.0000	1.0000	46.77
22.5	1,448,488	10,112	0.0070	0.9930	46.77
23.5	1,438,376		0.0000	1.0000	46.44
24.5	1,437,850		0.0000	1.0000	46.44
25.5	1,299,138	6,390	0.0049	0.9951	46.44
26.5	1,184,880		0.0000	1.0000	46.22
27.5	886,773		0.0000	1.0000	46.22
28.5	722,284		0.0000	1.0000	46.22
29.5	540,818		0.0000	1.0000	46.22
30.5	375,920		0.0000	1.0000	46.22
31.5	255,669		0.0000	1.0000	46.22
32.5	131,589		0.0000	1.0000	46.22
33.5	111,755		0.0000	1.0000	46.22
34.5	82,018		0.0000	1.0000	46.22
35.5	62,517		0.0000	1.0000	46.22
36.5	62,517		0.0000	1.0000	46.22
37.5	62,517		0.0000	1.0000	46.22
38.5	48,564	10,000	0.2059	0.7941	46.22

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 392.00 - TRANSPORTATION EQUIPMENT

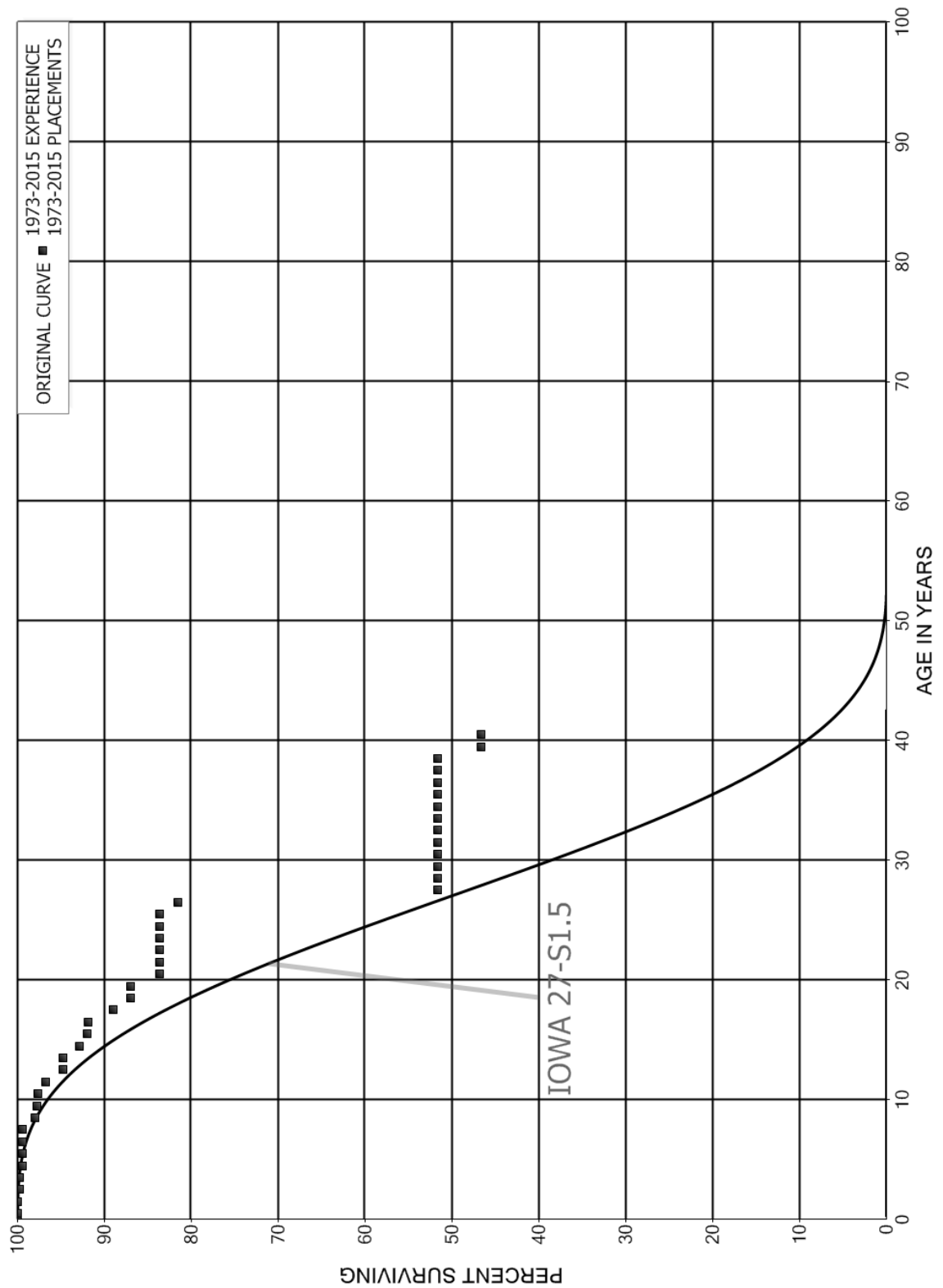
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2015

EXPERIENCE BAND 1963-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	38,564		0.0000	1.0000	36.70
40.5	38,564		0.0000	1.0000	36.70
41.5	20,222		0.0000	1.0000	36.70
42.5	20,222	10,222	0.5055	0.4945	36.70
43.5	10,000		0.0000	1.0000	18.15
44.5	10,000		0.0000	1.0000	18.15
45.5	10,000		0.0000	1.0000	18.15
46.5	10,000		0.0000	1.0000	18.15
47.5	10,000		0.0000	1.0000	18.15
48.5	10,000		0.0000	1.0000	18.15
49.5	10,000		0.0000	1.0000	18.15
50.5	10,000		0.0000	1.0000	18.15
51.5	10,000		0.0000	1.0000	18.15
52.5					18.15

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 396.00 - POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 396.00 - POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1973-2015

EXPERIENCE BAND 1973-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,581,077		0.0000	1.0000	100.00
0.5	5,544,163		0.0000	1.0000	100.00
1.5	5,538,619	17,831	0.0032	0.9968	100.00
2.5	5,150,014		0.0000	1.0000	99.68
3.5	5,150,014	14,202	0.0028	0.9972	99.68
4.5	5,047,486		0.0000	1.0000	99.40
5.5	4,484,807		0.0000	1.0000	99.40
6.5	3,664,126		0.0000	1.0000	99.40
7.5	2,999,823	45,364	0.0151	0.9849	99.40
8.5	2,871,592	5,185	0.0018	0.9982	97.90
9.5	2,826,600	1,898	0.0007	0.9993	97.72
10.5	2,515,012	22,731	0.0090	0.9910	97.66
11.5	2,489,571	52,520	0.0211	0.9789	96.77
12.5	2,418,487		0.0000	1.0000	94.73
13.5	1,947,702	39,913	0.0205	0.9795	94.73
14.5	1,907,789	17,538	0.0092	0.9908	92.79
15.5	1,181,469	901	0.0008	0.9992	91.94
16.5	1,159,592	36,617	0.0316	0.9684	91.87
17.5	822,822	19,170	0.0233	0.9767	88.97
18.5	803,652		0.0000	1.0000	86.90
19.5	803,652	30,000	0.0373	0.9627	86.90
20.5	773,652		0.0000	1.0000	83.65
21.5	773,652		0.0000	1.0000	83.65
22.5	773,652		0.0000	1.0000	83.65
23.5	773,652		0.0000	1.0000	83.65
24.5	703,602		0.0000	1.0000	83.65
25.5	703,602	18,398	0.0261	0.9739	83.65
26.5	498,395	182,350	0.3659	0.6341	81.46
27.5	217,557		0.0000	1.0000	51.66
28.5	217,557		0.0000	1.0000	51.66
29.5	179,972		0.0000	1.0000	51.66
30.5	160,632		0.0000	1.0000	51.66
31.5	158,055		0.0000	1.0000	51.66
32.5	158,055		0.0000	1.0000	51.66
33.5	158,055		0.0000	1.0000	51.66
34.5	150,105		0.0000	1.0000	51.66
35.5	150,105		0.0000	1.0000	51.66
36.5	150,105		0.0000	1.0000	51.66
37.5	125,105		0.0000	1.0000	51.66
38.5	119,705	11,664	0.0974	0.9026	51.66

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 396.00 - POWER OPERATED EQUIPMENT

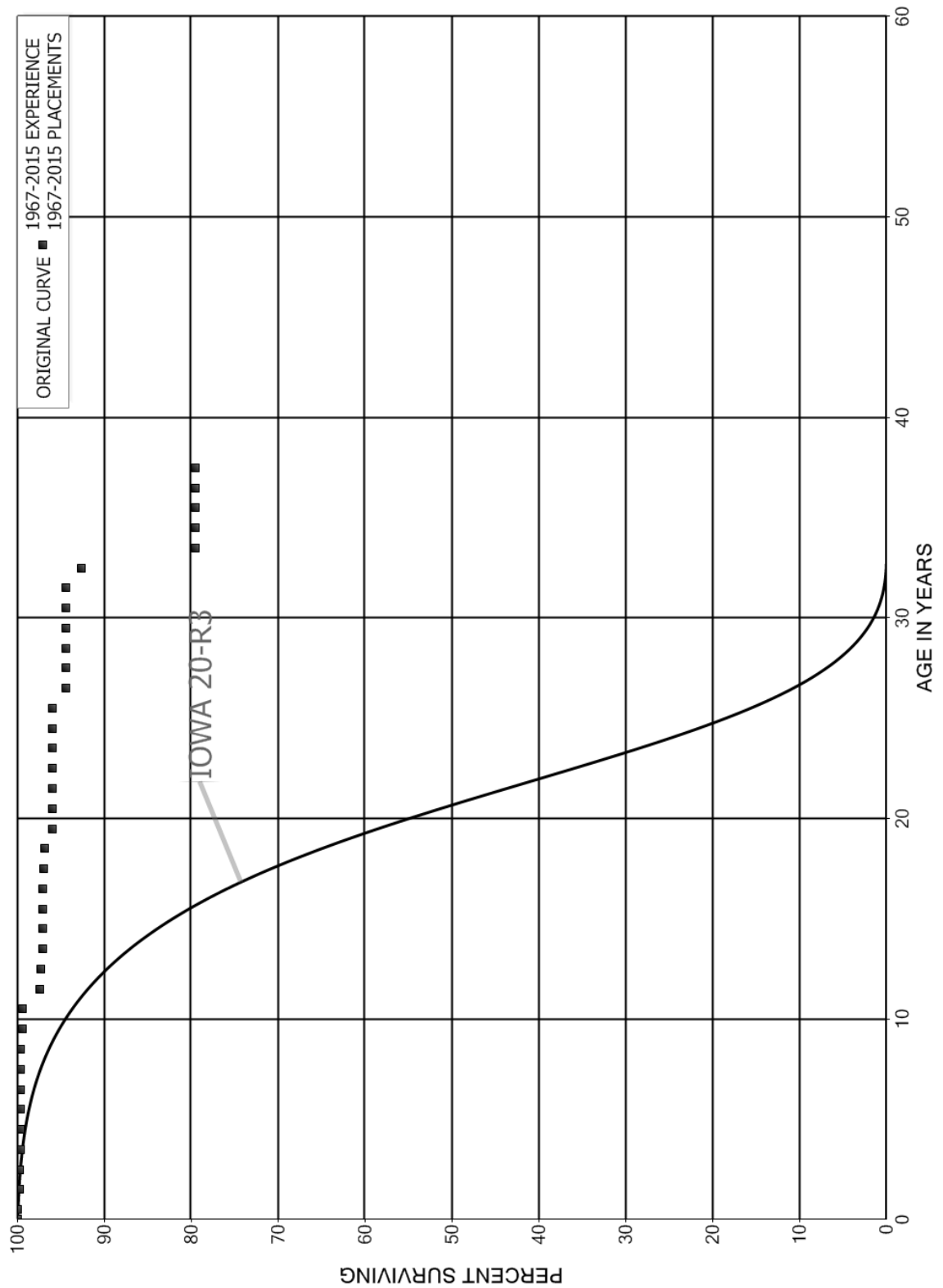
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1973-2015

EXPERIENCE BAND 1973-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	104,063		0.0000	1.0000	46.62
40.5	58,738		0.0000	1.0000	46.62
41.5					46.62

NORTHWEST TERRITORIES POWER CORPORATION
ACCOUNT 397.00 - COMMUNICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 397.00 - COMMUNICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015

EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,058,513		0.0000	1.0000	100.00
0.5	7,962,683	20,000	0.0025	0.9975	100.00
1.5	7,299,372		0.0000	1.0000	99.75
2.5	6,609,404	6,685	0.0010	0.9990	99.75
3.5	6,484,481		0.0000	1.0000	99.65
4.5	5,063,242		0.0000	1.0000	99.65
5.5	4,241,037		0.0000	1.0000	99.65
6.5	3,800,870		0.0000	1.0000	99.65
7.5	3,149,920		0.0000	1.0000	99.65
8.5	2,725,520	7,022	0.0026	0.9974	99.65
9.5	2,716,095		0.0000	1.0000	99.39
10.5	1,580,132	32,491	0.0206	0.9794	99.39
11.5	1,547,641	1,311	0.0008	0.9992	97.35
12.5	1,484,385	3,049	0.0021	0.9979	97.27
13.5	1,429,995		0.0000	1.0000	97.07
14.5	719,605		0.0000	1.0000	97.07
15.5	719,605	159	0.0002	0.9998	97.07
16.5	703,629	1,056	0.0015	0.9985	97.04
17.5	702,573	724	0.0010	0.9990	96.90
18.5	701,849	5,845	0.0083	0.9917	96.80
19.5	598,722		0.0000	1.0000	95.99
20.5	598,722		0.0000	1.0000	95.99
21.5	598,722		0.0000	1.0000	95.99
22.5	598,722		0.0000	1.0000	95.99
23.5	598,722		0.0000	1.0000	95.99
24.5	598,722		0.0000	1.0000	95.99
25.5	509,511	8,601	0.0169	0.9831	95.99
26.5	449,197		0.0000	1.0000	94.37
27.5	402,834		0.0000	1.0000	94.37
28.5	402,834		0.0000	1.0000	94.37
29.5	402,834		0.0000	1.0000	94.37
30.5	356,455		0.0000	1.0000	94.37
31.5	333,332	6,388	0.0192	0.9808	94.37
32.5	326,944	46,158	0.1412	0.8588	92.56
33.5	252,890		0.0000	1.0000	79.49
34.5	252,890		0.0000	1.0000	79.49
35.5	246,844		0.0000	1.0000	79.49
36.5	246,844		0.0000	1.0000	79.49
37.5	71,729		0.0000	1.0000	79.49
38.5	60,860		0.0000	1.0000	79.49

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 397.00 - COMMUNICATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015

EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	60,860		0.0000	1.0000	79.49
40.5	52,259		0.0000	1.0000	79.49
41.5	52,259		0.0000	1.0000	79.49
42.5	52,259		0.0000	1.0000	79.49
43.5	15,552		0.0000	1.0000	79.49
44.5	15,552		0.0000	1.0000	79.49
45.5	3,500		0.0000	1.0000	79.49
46.5	3,500		0.0000	1.0000	79.49
47.5					79.49

PART VI. NET SALVAGE STATISTICS

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 121.00 - WIND TURBINES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2009		96,083						96,083-	
2010									
2011									
2012									
2013	394,904		0	0		75,000	19	75,000	19
2014									
2015									
TOTAL	394,904	96,083	24	0		75,000	19	21,083-	5-
THREE-YEAR MOVING AVERAGES									
09-11		32,028						32,028-	
10-12									
11-13	131,635		0	0		25,000	19	25,000	19
12-14	131,635		0	0		25,000	19	25,000	19
13-15	131,635		0	0		25,000	19	25,000	19
FIVE-YEAR AVERAGE									
11-15	78,981		0	0		15,000	19	15,000	19

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 131.00 - RESIDUAL HEAT SYSTEM

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L AMOUNT		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2005	17,347		0		0		0		0
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013	119,564		0		0		0		0
2014									
2015	2,000		0		0		0		0
TOTAL	138,911		0		0		0		0
THREE-YEAR MOVING AVERAGES									
05-07	5,782		0		0		0		0
06-08									
07-09									
08-10									
09-11									
10-12									
11-13	39,855		0		0		0		0
12-14	39,855		0		0		0		0
13-15	40,521		0		0		0		0
FIVE-YEAR AVERAGE									
11-15	24,313		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 331.00 - HYDRO - STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2004	26,462	3,604	14		0		0	3,604-	14-
2005									
2006									
2007	23,912	11,928	50		0		0	11,928-	50-
2008		1,864						1,864-	
2009		131,450						131,450-	
2010		2,708						2,708-	
2011	6,355		0		0		0		0
2012	4,290		0		0		0		0
2013	67,695	31,000	46		0		0	31,000-	46-
2014	18,532	12,333	67		0		0	12,333-	67-
2015									
TOTAL	147,246	194,887	132		0		0	194,887-	132-

THREE-YEAR MOVING AVERAGES

04-06	8,821	1,201	14		0		0	1,201-	14-
05-07	7,971	3,976	50		0		0	3,976-	50-
06-08	7,971	4,597	58		0		0	4,597-	58-
07-09	7,971	48,414	607		0		0	48,414-	607-
08-10		45,341						45,341-	
09-11	2,118	44,719			0		0	44,719-	
10-12	3,548	903	25		0		0	903-	25-
11-13	26,114	10,333	40		0		0	10,333-	40-
12-14	30,172	14,444	48		0		0	14,444-	48-
13-15	28,742	14,444	50		0		0	14,444-	50-

FIVE-YEAR AVERAGE

11-15	19,374	8,666	45		0		0	8,666-	45-



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 332.00 - HYDRO - RESERVOIRS, DAMS AND WATERWAYS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	36,484	6,904	19		0		0	6,904-	19-
2004									
2005									
2006									
2007	480,340	447,637	93		0		0	447,637-	93-
2008	975,625	916,491	94		0		0	916,491-	94-
2009		16,379						16,379-	
2010	50,000	40,779	82		0		0	40,779-	82-
2011	124,570	102	0		0		0	102-	0
2012	5,265		0		0		0		0
2013	2,916,258	1,108,936	38		0		0	1,108,936-	38-
2014	78,332	55,931	71		0		0	55,931-	71-
2015	87,514	129,665	148		0		0	129,665-	148-
TOTAL	4,754,388	2,722,824	57		0		0	2,722,824-	57-

THREE-YEAR MOVING AVERAGES

03-05	12,161	2,301	19		0		0	2,301-	19-
04-06									
05-07	160,113	149,212	93		0		0	149,212-	93-
06-08	485,321	454,709	94		0		0	454,709-	94-
07-09	485,321	460,169	95		0		0	460,169-	95-
08-10	341,875	324,549	95		0		0	324,549-	95-
09-11	58,190	19,086	33		0		0	19,086-	33-
10-12	59,945	13,627	23		0		0	13,627-	23-
11-13	1,015,364	369,679	36		0		0	369,679-	36-
12-14	999,952	388,289	39		0		0	388,289-	39-
13-15	1,027,368	431,511	42		0		0	431,511-	42-

FIVE-YEAR AVERAGE

11-15	642,388	258,927	40		0		0	258,927-	40-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 333.00 - HYDRO - WATER WHEELS, TURBINES AND GENERATORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L S A L V A G E		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2003		45,969						45,969-	
2004	220,126	317,920	144		0		0	317,920-	144-
2005	60,745	5,042	8		0		0	5,042-	8-
2006	646,427	249,586	39		0		0	249,586-	39-
2007									
2008	141,970	86,324	61		0		0	86,324-	61-
2009		45,260						45,260-	
2010	301,856		0		0		0		0
2011									
2012									
2013									
2014									
2015									
TOTAL	1,371,125	750,101	55		0		0	750,101-	55-

THREE-YEAR MOVING AVERAGES

03-05	93,624	122,977	131		0		0	122,977-	131-
04-06	309,100	190,849	62		0		0	190,849-	62-
05-07	235,724	84,876	36		0		0	84,876-	36-
06-08	262,799	111,970	43		0		0	111,970-	43-
07-09	47,323	43,861	93		0		0	43,861-	93-
08-10	147,942	43,861	30		0		0	43,861-	30-
09-11	100,619	15,087	15		0		0	15,087-	15-
10-12	100,619		0		0		0		0
11-13									
12-14									
13-15									

FIVE-YEAR AVERAGE

11-15

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 334.00 - HYDRO - ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2004	5,745	1,037	18		0		0	1,037-	18-
2005	1,852	80,902			0		0	80,902-	
2006									
2007									
2008	186,838	104,521	56		0		0	104,521-	56-
2009		8,743						8,743-	
2010									
2011									
2012	22,435		0		0		0		0
2013	7,143	18,207	255		0		0	18,207-	255-
2014	30,795	30,369	99		0		0	30,369-	99-
2015									
TOTAL	254,809	243,780	96		0		0	243,780-	96-

THREE-YEAR MOVING AVERAGES

04-06	2,532	27,313			0		0	27,313-	
05-07	617	26,967			0		0	26,967-	
06-08	62,279	34,840	56		0		0	34,840-	56-
07-09	62,279	37,755	61		0		0	37,755-	61-
08-10	62,279	37,755	61		0		0	37,755-	61-
09-11		2,914						2,914-	
10-12	7,478		0		0		0		0
11-13	9,859	6,069	62		0		0	6,069-	62-
12-14	20,125	16,192	80		0		0	16,192-	80-
13-15	12,646	16,192	128		0		0	16,192-	128-

FIVE-YEAR AVERAGE

11-15	12,075	9,715	80		0		0	9,715-	80-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 335.00 - HYDRO - MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2004	16,458	5,184	32		0		0	5,184-	32-
2005									
2006									
2007		44,669						44,669-	
2008	620,779	70,296	11		0		0	70,296-	11-
2009									
2010									
2011	16,126		0		0		0		0
2012	1,000		0		0		0		0
2013	312,732	56,254	18		0		0	56,254-	18-
2014	347,103	2,291	1		0		0	2,291-	1-
2015									
TOTAL	1,314,198	178,693	14		0		0	178,693-	14-

THREE-YEAR MOVING AVERAGES

04-06	5,486	1,728	32		0		0	1,728-	32-
05-07		14,890						14,890-	
06-08	206,926	38,321	19		0		0	38,321-	19-
07-09	206,926	38,321	19		0		0	38,321-	19-
08-10	206,926	23,432	11		0		0	23,432-	11-
09-11	5,375		0		0		0		0
10-12	5,709		0		0		0		0
11-13	109,953	18,751	17		0		0	18,751-	17-
12-14	220,278	19,515	9		0		0	19,515-	9-
13-15	219,945	19,515	9		0		0	19,515-	9-

FIVE-YEAR AVERAGE

11-15	135,392	11,709	9		0		0	11,709-	9-



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 336.00 - HYDRO - ROADS, RAILROADS AND BRIDGES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001		10,358						10,358-	
2002	111,621		0		0		0		0
2003	44,322	2,986	7		0		0	2,986-	7-
2004									
2005	65,552	3,802	6		0		0	3,802-	6-
2006	21,558	1,000	5		0		0	1,000-	5-
2007									
2008	486,842	251,686	52		0		0	251,686-	52-
2009									
2010									
2011									
2012									
2013	5,538		0		0		0		0
2014									
2015									
TOTAL	735,432	269,832	37		0		0	269,832-	37-

THREE-YEAR MOVING AVERAGES

01-03	51,981	4,448	9		0		0	4,448-	9-
02-04	51,981	995	2		0		0	995-	2-
03-05	36,625	2,263	6		0		0	2,263-	6-
04-06	29,037	1,601	6		0		0	1,601-	6-
05-07	29,037	1,601	6		0		0	1,601-	6-
06-08	169,467	84,229	50		0		0	84,229-	50-
07-09	162,281	83,895	52		0		0	83,895-	52-
08-10	162,281	83,895	52		0		0	83,895-	52-
09-11									
10-12									
11-13	1,846		0		0		0		0
12-14	1,846		0		0		0		0
13-15	1,846		0		0		0		0

FIVE-YEAR AVERAGE

11-15	1,108		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 341.00 - DIESEL - STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L		N E T SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2002	58,903	14,137	24		0		0	14,137-	24-
2003	14,173	4,562	32		0		0	4,562-	32-
2004	99,638	49,528	50		0		0	49,528-	50-
2005	102,815		0		0		0		0
2006	226,855	23,865	11		0		0	23,865-	11-
2007	39,992	8,937	22		0		0	8,937-	22-
2008	101,956	56,243	55		0		0	56,243-	55-
2009									
2010									
2011	3,915		0		0		0		0
2012	49,229	30,337	62		0		0	30,337-	62-
2013	96,268	38,500	40		0	6,122	6	32,378-	34-
2014	15,229	3,600	24		0		0	3,600-	24-
2015	183,087	497,362	272		0		0	497,362-	272-
TOTAL	992,059	727,070	73		0	6,122	1	720,948-	73-

THREE-YEAR MOVING AVERAGES

02-04	57,571	22,742	40		0		0	22,742-	40-
03-05	72,209	18,030	25		0		0	18,030-	25-
04-06	143,103	24,464	17		0		0	24,464-	17-
05-07	123,221	10,934	9		0		0	10,934-	9-
06-08	122,934	29,682	24		0		0	29,682-	24-
07-09	47,316	21,727	46		0		0	21,727-	46-
08-10	33,985	18,748	55		0		0	18,748-	55-
09-11	1,305		0		0		0		0
10-12	17,714	10,112	57		0		0	10,112-	57-
11-13	49,804	22,946	46		0	2,041	4	20,905-	42-
12-14	53,575	24,146	45		0	2,041	4	22,105-	41-
13-15	98,195	179,821	183		0	2,041	2	177,780-	181-

FIVE-YEAR AVERAGE

11-15	69,545	113,960	164		0	1,224	2	112,735-	162-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 342.00 - DIESEL - FUEL HOLDERS, PRODUCERS AND ACCESSORIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L		N E T SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2003	162,860	79,889	49		0		0	79,889-	49-
2004	125,751	53,404	42		0		0	53,404-	42-
2005	269,535		0		0		0		0
2006									
2007	187,776	139,815	74		0		0	139,815-	74-
2008		265				1		264-	
2009		6,123						6,123-	
2010	124,135	38,903	31		0		0	38,903-	31-
2011	712,913		0		0		0		0
2012		562,971			0		0	562,971-	
2013		668,683			0		0	668,683-	
2014	169,275	600,900	355		0		0	600,900-	355-
2015	122,844	140,157	114		0		0	140,157-	114-
TOTAL	1,875,089	2,291,109	122		0	1	0	2,291,108-	122-

THREE-YEAR MOVING AVERAGES

03-05	186,049	44,431	24		0		0	44,431-	24-
04-06	131,762	17,801	14		0		0	17,801-	14-
05-07	152,437	46,605	31		0		0	46,605-	31-
06-08	62,592	46,693	75		0		0	46,693-	75-
07-09	62,592	48,734	78		0		0	48,734-	78-
08-10	41,378	15,097	36		0		0	15,097-	36-
09-11	279,016	15,009	5		0		0	15,009-	5-
10-12	279,016	200,625	72		0		0	200,625-	72-
11-13	237,638	410,551	173		0		0	410,551-	173-
12-14	56,425	610,851			0		0	610,851-	
13-15	97,373	469,913	483		0		0	469,913-	483-

FIVE-YEAR AVERAGE

11-15	201,006	394,542	196		0		0	394,542-	196-



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 343.00 - DIESEL - PRIME MOVERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2002	18,933		0		0		0		0
2003	686,562	310,196	45		0		0	310,196-	45-
2004	180,004	52,705	29		0		0	52,705-	29-
2005	2,245,032	11,253	1		0		0	11,253-	1-
2006	641,159	378,287	59		0		0	378,287-	59-
2007		21,996						21,996-	
2008	158,012	124,016	78		0	4,500	3	119,516-	76-
2009		189,025						189,025-	
2010	485,418	37,345	8		0		0	37,345-	8-
2011	100,872		0		0		0		0
2012	16,104	72,971	453		0		0	72,971-	453-
2013	169,937	171,859	101		0	1	0	171,858-	101-
2014	972,375	337,095	35		0	28,500	3	308,595-	32-
2015	1,616,587	47,218	3		0		0	47,218-	3-
TOTAL	7,290,995	1,753,967	24		0	33,001	0	1,720,966-	24-

THREE-YEAR MOVING AVERAGES

02-04	295,166	120,967	41		0		0	120,967-	41-
03-05	1,037,200	124,718	12		0		0	124,718-	12-
04-06	1,022,065	147,415	14		0		0	147,415-	14-
05-07	962,064	137,179	14		0		0	137,179-	14-
06-08	266,390	174,767	66		0	1,500	1	173,267-	65-
07-09	52,671	111,679	212		0	1,500	3	110,179-	209-
08-10	214,477	116,795	54		0	1,500	1	115,295-	54-
09-11	195,430	75,457	39		0		0	75,457-	39-
10-12	200,798	36,772	18		0		0	36,772-	18-
11-13	95,638	81,610	85		0		0	81,610-	85-
12-14	386,139	193,975	50		0	9,500	2	184,475-	48-
13-15	919,633	185,391	20		0	9,500	1	175,890-	19-

FIVE-YEAR AVERAGE

11-15	575,175	125,829	22		0	5,700	1	120,128-	21-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 344.00 - DIESEL- GENERATORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L AMOUNT		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2005	21,062		0		0		0		0
2006	90,433	66,341	73		0		0	66,341-	73-
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014	55,137		0		0		0		0
2015									
TOTAL	166,631	66,341	40		0		0	66,341-	40-
THREE-YEAR MOVING AVERAGES									
05-07	37,165	22,114	60		0		0	22,114-	60-
06-08	30,144	22,114	73		0		0	22,114-	73-
07-09									
08-10									
09-11									
10-12									
11-13									
12-14	18,379		0		0		0		0
13-15	18,379		0		0		0		0
FIVE-YEAR AVERAGE									
11-15	11,027		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 345.00 - DIESEL - ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E FINAL		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2002	47,624	12,335	26		0		0	12,335-	26-
2003	106,847	24,906	23		0		0	24,906-	23-
2004	23,219	4,974	21		0		0	4,974-	21-
2005	217,403	20,594	9		0		0	20,594-	9-
2006									
2007	154,573	21,448	14		0		0	21,448-	14-
2008	506,380	348,204	69		0		0	348,204-	69-
2009						2,419		2,419	
2010	43,275	83,151	192		0		0	83,151-	192-
2011	156,000		0		0		0		0
2012	159,080	54,135	34		0	6,000	4	48,135-	30-
2013	7,031	5,000	71		0		0	5,000-	71-
2014	260,670		0		0		0		0
2015	406,860	20,768	5		0		0	20,768-	5-
TOTAL	2,088,962	595,516	29		0	8,419	0	587,096-	28-

THREE-YEAR MOVING AVERAGES

02-04	59,230	14,072	24		0		0	14,072-	24-
03-05	115,823	16,824	15		0		0	16,824-	15-
04-06	80,208	8,522	11		0		0	8,522-	11-
05-07	123,992	14,014	11		0		0	14,014-	11-
06-08	220,318	123,217	56		0		0	123,217-	56-
07-09	220,318	123,217	56		0	806	0	122,411-	56-
08-10	183,219	143,785	78		0	806	0	142,979-	78-
09-11	66,425	27,717	42		0	806	1	26,911-	41-
10-12	119,452	45,762	38		0	2,000	2	43,762-	37-
11-13	107,370	19,712	18		0	2,000	2	17,712-	16-
12-14	142,260	19,712	14		0	2,000	1	17,712-	12-
13-15	224,853	8,589	4		0		0	8,589-	4-

FIVE-YEAR AVERAGE

11-15	197,928	15,981	8		0	1,200	1	14,781-	7-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 346.00 - DIESEL - MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L S A L V A G E		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2002	51,467		0		0		0		0
2003	466	278	60		0		0	278-	60-
2004									
2005	39,062		0		0		0		0
2006									
2007									
2008									
2009		14,083						14,083-	
2010									
2011									
2012									
2013									
2014									
2015									
TOTAL	90,995	14,361	16		0		0	14,361-	16-

THREE-YEAR MOVING AVERAGES

02-04	17,311	93	1		0		0	93-	1-
03-05	13,176	93	1		0		0	93-	1-
04-06	13,021		0		0		0		0
05-07	13,021		0		0		0		0
06-08									
07-09		4,694						4,694-	
08-10		4,694						4,694-	
09-11		4,694						4,694-	
10-12									
11-13									
12-14									
13-15									

FIVE-YEAR AVERAGE

11-15

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 353.00 - TRANSMISSION - STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L S A L V A G E		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2003	112,349	22,335	20		0		0	22,335-	20-
2004	103,430	16,259	16		0		0	16,259-	16-
2005	284,759		0		0		0		0
2006									
2007	43,585	38,711	89		0		0	38,711-	89-
2008	469,659	322,478	69		0		0	322,478-	69-
2009									
2010		9,667						9,667-	
2011	12,776		0		0		0		0
2012	38,138		0		0		0		0
2013									
2014	200,951	80,161	40		0		0	80,161-	40-
2015	15,283	42,910	281		0		0	42,910-	281-
TOTAL	1,280,931	532,521	42		0		0	532,521-	42-

THREE-YEAR MOVING AVERAGES

03-05	166,846	12,865	8		0		0	12,865-	8-
04-06	129,397	5,420	4		0		0	5,420-	4-
05-07	109,448	12,904	12		0		0	12,904-	12-
06-08	171,081	120,396	70		0		0	120,396-	70-
07-09	171,081	120,396	70		0		0	120,396-	70-
08-10	156,553	110,715	71		0		0	110,715-	71-
09-11	4,259	3,222	76		0		0	3,222-	76-
10-12	16,972	3,222	19		0		0	3,222-	19-
11-13	16,972		0		0		0		0
12-14	79,696	26,720	34		0		0	26,720-	34-
13-15	72,078	41,024	57		0		0	41,024-	57-

FIVE-YEAR AVERAGE

11-15	53,430	24,614	46		0		0	24,614-	46-



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 354.00 - TRANSMISSION - TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2003	1,059	182	17		0		0	182-	17-
2004	9,017	1,331	15		0		0	1,331-	15-
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015	1,374		0		0		0		0
TOTAL	11,451	1,513	13		0		0	1,513-	13-

THREE-YEAR MOVING AVERAGES

03-05	3,359	504	15		0		0	504-	15-
04-06	3,006	444	15		0		0	444-	15-
05-07									
06-08									
07-09									
08-10									
09-11									
10-12									
11-13									
12-14									
13-15	458		0		0		0		0

FIVE-YEAR AVERAGE

11-15	275		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 356.00 - TRANSMISSION - OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2009		106,753						106,753-	
2010									
2011	274,019		0		0		0		0
2012									
2013									
2014									
2015									
TOTAL	274,019	106,753	39		0		0	106,753-	39-
THREE-YEAR MOVING AVERAGES									
09-11	91,340	35,584	39		0		0	35,584-	39-
10-12	91,340		0		0		0		0
11-13	91,340		0		0		0		0
12-14									
13-15									
FIVE-YEAR AVERAGE									
11-15	54,804		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 362.00 - DISTRIBUTION - STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2002	22,014	5,037	23		0		0	5,037-	23-
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
TOTAL	22,014	5,037	23		0		0	5,037-	23-

THREE-YEAR MOVING AVERAGES

02-04	7,338	1,679	23		0		0	1,679-	23-
03-05									
04-06									
05-07									
06-08									
07-09									
08-10									
09-11									
10-12									
11-13									
12-14									
13-15									

FIVE-YEAR AVERAGE

11-15



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 364.00 - DISTRIBUTION - POLES, TOWERS, AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L S A L V A G E		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2002	40,588	15,131	37		0		0	15,131-	37-
2003	27,136	12,667	47		0		0	12,667-	47-
2004	9,600	3,030	32		0		0	3,030-	32-
2005	47,789		0		0		0		0
2006	36,976	7,277	20		0		0	7,277-	20-
2007	90,606	18,917	21		0		0	18,917-	21-
2008	26,628	2,482	9		0		0	2,482-	9-
2009									
2010									
2011									
2012	27,417		0		0		0		0
2013									
2014	22,496	3,776	17		0		0	3,776-	17-
2015	29,411	18,790	64		0		0	18,790-	64-
TOTAL	358,648	82,070	23		0		0	82,070-	23-

THREE-YEAR MOVING AVERAGES

02-04	25,775	10,276	40		0		0	10,276-	40-
03-05	28,175	5,232	19		0		0	5,232-	19-
04-06	31,455	3,436	11		0		0	3,436-	11-
05-07	58,457	8,731	15		0		0	8,731-	15-
06-08	51,403	9,559	19		0		0	9,559-	19-
07-09	39,078	7,133	18		0		0	7,133-	18-
08-10	8,876	827	9		0		0	827-	9-
09-11									
10-12	9,139		0		0		0		0
11-13	9,139		0		0		0		0
12-14	16,638	1,259	8		0		0	1,259-	8-
13-15	17,302	7,522	43		0		0	7,522-	43-

FIVE-YEAR AVERAGE

11-15	15,865	4,513	28		0		0	4,513-	28-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 365.00 - DISTRIBUTION - OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2007	13,668	1,911	14		0		0	1,911-	14-
2008									
2009									
2010									
2011									
2012									
2013									
2014	3,102	2,618	84		0		0	2,618-	84-
2015									
TOTAL	16,771	4,529	27		0		0	4,529-	27-
THREE-YEAR MOVING AVERAGES									
07-09	4,556	637	14		0		0	637-	14-
08-10									
09-11									
10-12									
11-13									
12-14	1,034	873	84		0		0	873-	84-
13-15	1,034	873	84		0		0	873-	84-
FIVE-YEAR AVERAGE									
11-15	620	524	84		0		0	524-	84-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 367.00 - DISTRIBUTION - UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L AMOUNT		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2013	7,920		0		0		0		0
2014									
2015									
TOTAL	7,920		0		0		0		0
THREE-YEAR MOVING AVERAGES									
13-15	2,640		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 368.00 - DISTRIBUTION - LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2007	2,571	221	9		0		0	221-	9-
2008									
2009									
2010		2,970				1,581		1,389-	
2011	22,453		0		0		0		0
2012	25,847		0		0		0		0
2013	47,035		0		0	600	1	600	1
2014									
2015	97,699		0		0	1,375	1	1,375	1
TOTAL	195,606	3,191	2		0	3,556	2	365	0

THREE-YEAR MOVING AVERAGES

07-09	857	74	9		0		0	74-	9-
08-10		990				527		463-	
09-11	7,484	990	13		0	527	7	463-	6-
10-12	16,100	990	6		0	527	3	463-	3-
11-13	31,779		0		0	200	1	200	1
12-14	24,294		0		0	200	1	200	1
13-15	48,245		0		0	658	1	658	1

FIVE-YEAR AVERAGE

11-15	38,607		0		0	395	1	395	1

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 369.00 - DISTRIBUTION - SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2009		284						284-	
2010	6,163		0		0		0		0
2011									
2012	20,248		0		0		0		0
2013									
2014	883		0		0		0		0
2015	500		0		0		0		0
TOTAL	27,793	284	1		0		0	284-	1-

THREE-YEAR MOVING AVERAGES

09-11	2,054	95	5		0		0	95-	5-
10-12	8,803		0		0		0		0
11-13	6,749		0		0		0		0
12-14	7,043		0		0		0		0
13-15	461		0		0		0		0

FIVE-YEAR AVERAGE

11-15	4,326		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 370.00 - DISTRIBUTION - METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2012	801,767		0		0		0		0
2013	73,347		0		0		0		0
2014	53,904		0		0		0		0
2015	43,938		0		0		0		0
TOTAL	972,955		0		0		0		0
THREE-YEAR MOVING AVERAGES									
12-14	309,672		0		0		0		0
13-15	57,063		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 373.00 - DISTRIBUTION - STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2009		43,204						43,204-	
2010									
2011									
2012	8,572		0		0		0		0
2013									
2014	2,090	6,055	290		0		0	6,055-	290-
2015	19,856		0		0		0		0
TOTAL	30,517	49,260	161		0		0	49,260-	161-

THREE-YEAR MOVING AVERAGES

09-11		14,401						14,401-	
10-12	2,857		0		0		0		0
11-13	2,857		0		0		0		0
12-14	3,554	2,018	57		0		0	2,018-	57-
13-15	7,315	2,018	28		0		0	2,018-	28-

FIVE-YEAR AVERAGE

11-15	6,103	1,211	20		0		0	1,211-	20-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 382.00 - COMPUTER HARDWARE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L AMOUNT		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2014	2,780		0		0		0		0
2015	19,153		0		0		0		0
TOTAL	21,933		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 390.02 - STRUCTURES AND IMPROVEMENTS - OTHER SMALL STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2002	44,038		0		0		0		0
2003									
2004	19,252	9,773	51		0		0	9,773-	51-
2005	58,686	15,667	27		0		0	15,667-	27-
2006	21,997	6,071	28		0		0	6,071-	28-
2007		1,985						1,985-	
2008		16,144						16,144-	
2009		25,698				6,442		19,256-	
2010		468,892						468,892-	
2011	759,070		0		0		0		0
2012	180,899	4,250	2		0		0	4,250-	2-
2013	16,100		0		0		0		0
2014	213,670	3,800	2		0		0	3,800-	2-
2015	191,836	82,021	43		0		0	82,021-	43-
TOTAL	1,505,548	634,302	42		0	6,442	0	627,860-	42-

THREE-YEAR MOVING AVERAGES

02-04	21,097	3,258	15		0		0	3,258-	15-
03-05	25,979	8,480	33		0		0	8,480-	33-
04-06	33,312	10,504	32		0		0	10,504-	32-
05-07	26,894	7,908	29		0		0	7,908-	29-
06-08	7,332	8,067	110		0		0	8,067-	110-
07-09		14,609				2,147		12,462-	
08-10		170,245				2,147		168,097-	
09-11	253,023	164,863	65		0	2,147	1	162,716-	64-
10-12	313,323	157,714	50		0		0	157,714-	50-
11-13	318,690	1,417	0		0		0	1,417-	0
12-14	136,890	2,683	2		0		0	2,683-	2-
13-15	140,535	28,607	20		0		0	28,607-	20-

FIVE-YEAR AVERAGE

11-15	272,315	18,014	7		0		0	18,014-	7-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 391.00 - OFFICE FURNITURE AND EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2002	4,350		0		0		0		0
2003									
2004	103,394	60,547	59		0		0	60,547-	59-
2005	855,519		0		0		0		0
2006									
2007		208,884						208,884-	
2008									
2009									
2010									
2011	3,150		0		0		0		0
2012	856,784		0		0		0		0
2013	530,474		0		0		0		0
2014	10,094		0		0		0		0
2015	874,163	1,359	0		0	1,914	0	555	0
TOTAL	3,237,926	270,791	8		0	1,914	0	268,876-	8-

THREE-YEAR MOVING AVERAGES

02-04	35,914	20,182	56		0		0	20,182-	56-
03-05	319,637	20,182	6		0		0	20,182-	6-
04-06	319,637	20,182	6		0		0	20,182-	6-
05-07	285,173	69,628	24		0		0	69,628-	24-
06-08		69,628						69,628-	
07-09		69,628						69,628-	
08-10									
09-11	1,050		0		0		0		0
10-12	286,645		0		0		0		0
11-13	463,469		0		0		0		0
12-14	465,784		0		0		0		0
13-15	471,577	453	0		0	638	0	185	0

FIVE-YEAR AVERAGE

11-15	454,933	272	0		0	383	0	111	0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 392.00 - TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L PCT		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2002	10,000		0		0		0		0
2003	204,273		0		0		0		0
2004	65,358		0		0		0		0
2005	95,001		0		0		0		0
2006									
2007		4,307				51		4,256-	
2008		32,960						32,960-	
2009		64,130				11,996		52,134-	
2010	221,710	51,172	23		0	2,975	1	48,197-	22-
2011	166,332		0		0		0		0
2012	111,730		0		0	6,945	6	6,945	6
2013	565,866	42	0		0	9,450	2	9,408	2
2014	160,929	1,130	1		0	16,287	10	15,157	9
2015	124,377	10,421	8		0		0	10,421-	8-
TOTAL	1,725,575	164,164	10		0	47,704	3	116,460-	7-

THREE-YEAR MOVING AVERAGES

02-04	93,210		0		0		0		0
03-05	121,544		0		0		0		0
04-06	53,453		0		0		0		0
05-07	31,667	1,436	5		0	17	0	1,419-	4-
06-08		12,423				17		12,406-	
07-09		33,799				4,016		29,784-	
08-10	73,903	49,421	67		0	4,990	7	44,431-	60-
09-11	129,347	38,434	30		0	4,990	4	33,444-	26-
10-12	166,591	17,057	10		0	3,307	2	13,751-	8-
11-13	281,309	14	0		0	5,465	2	5,451	2
12-14	279,508	391	0		0	10,894	4	10,503	4
13-15	283,724	3,865	1		0	8,579	3	4,714	2

FIVE-YEAR AVERAGE

11-15	225,847	2,319	1		0	6,536	3	4,218	2

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 393.00 - STORES EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L		N E T	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2005	3,096		0		0		0		0
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
TOTAL	3,096		0		0		0		0
THREE-YEAR MOVING AVERAGES									
05-07	1,032		0		0		0		0
06-08									
07-09									
08-10									
09-11									
10-12									
11-13									
12-14									
13-15									
FIVE-YEAR AVERAGE									
11-15									

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 394.00 - TOOLS, SHOP AND GARAGE EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L AMOUNT		N E T SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2014	8,787		0		0	595	7	595	7
2015									
TOTAL	8,787		0		0	595	7	595	7

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 395.00 - LABORATORY EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L AMOUNT		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2013	29,095		0		0		0		0
2014									
2015									
TOTAL	29,095		0		0		0		0
THREE-YEAR MOVING AVERAGES									
13-15	9,698		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 396.00 - POWER OPERATED EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2002	14,202		0		0		0		0
2003									
2004									
2005									
2006									
2007									
2008		3,831						3,831-	
2009		15,453						15,453-	
2010						6,300		6,300	
2011	215,266		0		0		0		0
2012									
2013									
2014									
2015	29,296		0		0	4,050	14	4,050	14
TOTAL	258,764	19,283	7		0	10,350	4	8,933-	3-

THREE-YEAR MOVING AVERAGES

02-04	4,734		0		0		0		0
03-05									
04-06									
05-07									
06-08		1,277						1,277-	
07-09		6,428						6,428-	
08-10		6,428				2,100		4,328-	
09-11	71,755	5,151	7		0	2,100	3	3,051-	4-
10-12	71,755		0		0	2,100	3	2,100	3
11-13	71,755		0		0		0		0
12-14									
13-15	9,765		0		0	1,350	14	1,350	14

FIVE-YEAR AVERAGE

11-15	48,913		0		0	810	2	810	2

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 397.00 - COMMUNICATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2005	20,000	17,760	89		0		0	17,760-	89-
2006									
2007		3,738						3,738-	
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015	32,625	1,014	3		0		0	1,014-	3-
TOTAL	52,625	22,512	43		0		0	22,512-	43-

THREE-YEAR MOVING AVERAGES

05-07	6,667	7,166	107		0		0	7,166-	107-
06-08		1,246						1,246-	
07-09		1,246						1,246-	
08-10									
09-11									
10-12									
11-13									
12-14									
13-15	10,875	338	3		0		0	338-	3-

FIVE-YEAR AVERAGE

11-15	6,525	203	3		0		0	203-	3-

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 398.00 - MISCELLANEOUS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L AMOUNT		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2013	18,222		0		0		0		0
2014									
2015									
TOTAL	18,222		0		0		0		0
THREE-YEAR MOVING AVERAGES									
13-15	6,074		0		0		0		0

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 399.00 - OTHER TANGIBLE PROPERTY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2008	75,014	53,584	71		0		0	53,584-	71-
2009									
2010									
2011									
2012									
2013									
2014									
2015									
TOTAL	75,014	53,584	71		0		0	53,584-	71-
THREE-YEAR MOVING AVERAGES									
08-10	25,005	17,861	71		0		0	17,861-	71-
09-11									
10-12									
11-13									
12-14									
13-15									
FIVE-YEAR AVERAGE									
11-15									

PART VII. DETAILED DEPRECIATION CALCULATIONS

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 118.00 - WATER AND SEWER EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 25-R3							
NET SALVAGE PERCENT.. 0							
2010	404,904.18	25.00	4.00	16,196.17	20.39	0.1844	74,664
2012	348,192.70	25.00	4.00	13,927.71	22.31	0.1076	37,466
2013	331,205.03	25.00	4.00	13,248.20	23.28	0.0688	22,787
2014	468,125.06	25.00	4.00	18,725.00	24.26	0.0296	13,857
	1,552,426.97			62,097.08			148,774
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.00							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 121.00 - RESIDUAL HEAT SYSTEMS - WIND TURBINES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 40-R3							
NET SALVAGE PERCENT.. -10							
1999	353,262.83	40.00	2.50	9,714.73	25.15	0.3713	144,264
	353,262.83			9,714.73			144,264
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.75							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 131.00 - RESIDUAL HEAT SYSTEM

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 28-R4							
NET SALVAGE PERCENT.. 0							
1999	196,370.95	28.00	3.57	7,010.44	12.77	0.5439	106,812
2000	2,171,521.96	28.00	3.57	77,523.33	13.66	0.5121	1,112,123
2001	111,818.89	28.00	3.57	3,991.93	14.56	0.4800	53,673
2003	119,564.14	28.00	3.57	4,268.44	16.43	0.4132	49,405
2005	174,380.88	28.00	3.57	6,225.40	18.34	0.3450	60,161
2007	25,917.30	28.00	3.57	925.25	20.30	0.2750	7,127
2011	2,260,746.90	28.00	3.57	80,708.66	24.26	0.1336	301,968
2013	5,833.86	28.00	3.57	208.27	26.25	0.0625	365
2014	590,525.91	28.00	3.57	21,081.77	27.25	0.0268	15,820
	5,656,680.79			201,943.49			1,707,454
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.57							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 331.00 - HYDRO - STRUCTURES AND IMPROVEMENTS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 100-R3							
NET SALVAGE PERCENT.. -5							
1962	1,808,521.09	100.00	1.00	18,989.47	51.53	0.4847	920,420
1967	2,275,750.31	100.00	1.00	23,895.38	55.67	0.4433	1,059,282
1977	1,554,008.38	100.00	1.00	16,317.09	64.31	0.3569	582,357
1978	4,897,899.81	100.00	1.00	51,427.95	65.20	0.3480	1,789,693
1982	23,323.93	100.00	1.00	244.90	68.79	0.3121	7,643
1995	189,382.72	100.00	1.00	1,988.52	80.86	0.1914	38,060
1996	6,721,407.17	100.00	1.00	70,574.78	81.81	0.1819	1,283,755
1997	102,546.46	100.00	1.00	1,076.74	82.76	0.1724	18,563
1998	79,742.09	100.00	1.00	837.29	83.71	0.1629	13,639
1999	78,860.13	100.00	1.00	828.03	84.67	0.1533	12,694
2000	34,343.84	100.00	1.00	360.61	85.63	0.1437	5,182
2002	6,623.21	100.00	1.00	69.54	87.56	0.1244	865
2003	73,535.33	100.00	1.00	772.12	88.52	0.1148	8,864
2004	1,425,142.56	100.00	1.00	14,964.00	89.49	0.1051	157,272
2005	29,296.59	100.00	1.00	307.61	90.46	0.0954	2,935
2006	310,616.14	100.00	1.00	3,261.47	91.43	0.0857	27,951
2007	249,354.60	100.00	1.00	2,618.22	92.40	0.0760	19,898
2008	270,208.27	100.00	1.00	2,837.19	93.38	0.0662	18,782
2009	835,345.55	100.00	1.00	8,771.13	94.36	0.0564	49,469
2010	45,906.35	100.00	1.00	482.02	95.33	0.0467	2,251
2011	41,435.71	100.00	1.00	435.07	96.31	0.0369	1,605
2012	903,119.69	100.00	1.00	9,482.76	97.30	0.0270	25,603
2013	466,122.84	100.00	1.00	4,894.29	98.28	0.0172	8,418
2014	173,007.00	100.00	1.00	1,816.57	99.26	0.0074	1,344
2015	2,997.00	100.00	1.00	31.47	99.88	0.0012	4
22,598,496.77				237,284.22	6,056,549		

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.05

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 332.00 - HYDRO - RESERVOIRS, DAMS AND WATERWAYS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 100-R3							
NET SALVAGE PERCENT.. -5							
1949	990,299.53	100.00	1.00	10,398.15	41.37	0.5863	609,643
1962	1,818,565.08	100.00	1.00	19,094.93	51.53	0.4847	925,531
1967	2,326,994.18	100.00	1.00	24,433.44	55.67	0.4433	1,083,134
1968	493,401.25	100.00	1.00	5,180.71	56.52	0.4348	225,257
1978	11,439,916.35	100.00	1.00	120,119.12	65.20	0.3480	4,180,145
1993	45,960.11	100.00	1.00	482.58	78.97	0.2103	10,149
1995	8,204.67	100.00	1.00	86.15	80.86	0.1914	1,649
1996	6,264,737.83	100.00	1.00	65,779.75	81.81	0.1819	1,196,534
1999	289,001.98	100.00	1.00	3,034.52	84.67	0.1533	46,519
2000	9,536.28	100.00	1.00	100.13	85.63	0.1437	1,439
2001	96,416.88	100.00	1.00	1,012.38	86.59	0.1341	13,576
2003	391,540.76	100.00	1.00	4,111.18	88.52	0.1148	47,196
2004	2,780,157.68	100.00	1.00	29,191.66	89.49	0.1051	306,804
2005	6,684.55	100.00	1.00	70.19	90.46	0.0954	670
2006	296,453.35	100.00	1.00	3,112.76	91.43	0.0857	26,676
2007	7,890,694.70	100.00	1.00	82,852.29	92.40	0.0760	629,677
2008	117,686.20	100.00	1.00	1,235.71	93.38	0.0662	8,180
2009	1,428,544.41	100.00	1.00	14,999.72	94.36	0.0564	84,598
2010	2,260,412.33	100.00	1.00	23,734.33	95.33	0.0467	110,839
2011	172,251.50	100.00	1.00	1,808.64	96.31	0.0369	6,674
2012	29,899,873.38	100.00	1.00	313,948.67	97.30	0.0270	847,661
2013	164,957.09	100.00	1.00	1,732.05	98.28	0.0172	2,979
2014	874,937.78	100.00	1.00	9,186.85	99.26	0.0074	6,798
2015	212,210.52	100.00	1.00	2,228.21	99.88	0.0012	267
70,279,438.39				737,934.12	10,372,595		

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.05

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 333.00 - HYDRO - WATER WHEELS, TURBINES AND GENERATORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 50-S2							
NET SALVAGE PERCENT.. -5							
1962	305,204.30	50.00	2.00	6,409.29	11.62	0.7676	245,989
1967	926,509.05	50.00	2.00	19,456.69	13.59	0.7282	708,418
1977	1,428,263.47	50.00	2.00	29,993.53	18.39	0.6322	948,096
1978	849,482.63	50.00	2.00	17,839.14	18.95	0.6210	553,905
1986	1,425,945.32	50.00	2.00	29,944.85	23.98	0.5204	779,165
1989	131,634.25	50.00	2.00	2,764.32	26.16	0.4768	65,901
1991	146,043.13	50.00	2.00	3,066.91	27.71	0.4458	68,361
1993	46,155.64	50.00	2.00	969.27	29.32	0.4136	20,044
1995	473,565.87	50.00	2.00	9,944.88	31.01	0.3798	188,853
1996	10,105,674.58	50.00	2.00	212,219.17	31.88	0.3624	3,845,411
1997	2,425,338.39	50.00	2.00	50,932.11	32.76	0.3448	878,070
1998	952,736.42	50.00	2.00	20,007.46	33.66	0.3268	326,922
1999	40,325.42	50.00	2.00	846.83	34.58	0.3084	13,058
2000	97,623.00	50.00	2.00	2,050.08	35.50	0.2900	29,726
2002	41,926.41	50.00	2.00	880.45	37.39	0.2522	11,103
2003	1,187,724.98	50.00	2.00	24,942.22	38.35	0.2330	290,577
2004	2,130,809.74	50.00	2.00	44,747.00	39.32	0.2136	477,898
2005	4,315,861.73	50.00	2.00	90,633.10	40.30	0.1940	879,141
2006	7,862.09	50.00	2.00	165.10	41.28	0.1744	1,440
2007	246,219.25	50.00	2.00	5,170.60	42.27	0.1546	39,969
2008	634,808.74	50.00	2.00	13,330.98	43.26	0.1348	89,851
2009	331,575.28	50.00	2.00	6,963.08	44.25	0.1150	40,038
2012	248,526.95	50.00	2.00	5,219.07	47.25	0.0550	14,352
2014	1,362,296.04	50.00	2.00	28,608.22	49.25	0.0150	21,456
2015	2,282,992.25	50.00	2.00	47,942.84	49.88	0.0024	5,753
32,145,104.93				675,047.19	10,543,497		

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.10

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 334.00 - HYDRO - ACCESSORY ELECTRIC EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 40-R2.5							
NET SALVAGE PERCENT.. -5							
1962	179,788.45	40.00	2.50	4,719.45	5.26	0.8685	163,954
1967	247,904.82	40.00	2.50	6,507.50	6.63	0.8343	217,155
1978	4,393,204.04	40.00	2.50	115,321.61	11.16	0.7210	3,325,875
1983	126,341.59	40.00	2.50	3,316.47	14.06	0.6485	86,029
1985	12,473.05	40.00	2.50	327.42	15.34	0.6165	8,074
1986	269,205.18	40.00	2.50	7,066.64	16.00	0.6000	169,599
1987	189,644.88	40.00	2.50	4,978.18	16.69	0.5828	116,041
1989	209,248.75	40.00	2.50	5,492.78	18.09	0.5478	120,347
1991	16,778.16	40.00	2.50	440.43	19.55	0.5113	9,007
1993	384,154.31	40.00	2.50	10,084.05	21.06	0.4735	190,992
1995	94,261.68	40.00	2.50	2,474.37	22.62	0.4345	43,005
1996	3,171,609.00	40.00	2.50	83,254.74	23.42	0.4145	1,380,364
1997	251,776.22	40.00	2.50	6,609.13	24.22	0.3945	104,292
1998	115,900.11	40.00	2.50	3,042.38	25.04	0.3740	45,514
1999	78,536.32	40.00	2.50	2,061.58	25.87	0.3533	29,130
2003	258,062.27	40.00	2.50	6,774.13	29.28	0.2680	72,619
2004	1,301,949.92	40.00	2.50	34,176.19	30.15	0.2463	336,635
2005	12,424.19	40.00	2.50	326.13	31.04	0.2240	2,922
2008	1,072,240.65	40.00	2.50	28,146.32	33.73	0.1568	176,477
2009	5,618,806.94	40.00	2.50	147,493.68	34.64	0.1340	790,566
2010	361,404.50	40.00	2.50	9,486.87	35.56	0.1110	42,122
2011	830,116.59	40.00	2.50	21,790.56	36.49	0.0878	76,485
2012	1,817,666.61	40.00	2.50	47,713.75	37.42	0.0645	123,101
2013	814,368.89	40.00	2.50	21,377.18	38.35	0.0413	35,272
2014	1,149,365.05	40.00	2.50	30,170.83	39.29	0.0178	21,421
22,977,232.17				603,152.37	7,686,998		

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.63

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 335.00 - HYDRO - MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 20-R2							
NET SALVAGE PERCENT.. -8							
1962	20,950.21	20.00				1.0000	22,626
1967	79,978.25	20.00				1.0000	86,377
1979	31,054.98	20.00	5.00	1,676.97	0.36	0.9820	32,936
1981	4,211.03	20.00	5.00	227.40	0.89	0.9555	4,346
1982	6,495.85	20.00	5.00	350.78	1.17	0.9415	6,605
1984	18,830.67	20.00	5.00	1,016.86	1.75	0.9125	18,558
1985	9,677.62	20.00	5.00	522.59	2.04	0.8980	9,386
1988	30,784.25	20.00	5.00	1,662.35	2.94	0.8530	28,360
1989	19,097.30	20.00	5.00	1,031.25	3.26	0.8370	17,263
1991	700,390.40	20.00	5.00	37,821.08	3.95	0.8025	607,028
1996	758,449.09	20.00	5.00	40,956.25	6.15	0.6925	567,244
1997	93,001.03	20.00	5.00	5,022.06	6.68	0.6660	66,894
1998	134,046.08	20.00	5.00	7,238.49	7.24	0.6380	92,363
1999	69,277.54	20.00	5.00	3,740.99	7.82	0.6090	45,565
2000	186,529.23	20.00	5.00	10,072.58	8.43	0.5785	116,540
2001	30,632.98	20.00	5.00	1,654.18	9.07	0.5465	18,080
2003	24,390.51	20.00	5.00	1,317.09	10.43	0.4785	12,605
2004	550,213.32	20.00	5.00	29,711.52	11.14	0.4430	263,244
2006	46,788.20	20.00	5.00	2,526.56	12.63	0.3685	18,621
2007	141,396.42	20.00	5.00	7,635.41	13.41	0.3295	50,317
2009	161,131.59	20.00	5.00	8,701.11	15.02	0.2490	43,332
2010	278,639.80	20.00	5.00	15,046.55	15.85	0.2075	62,443
2011	39,849.23	20.00	5.00	2,151.86	16.69	0.1655	7,123
2012	59,082.10	20.00	5.00	3,190.43	17.56	0.1220	7,785
2013	32,973.94	20.00	5.00	1,780.59	18.43	0.0785	2,796
2014	5,251.73	20.00	5.00	283.59	19.32	0.0340	193
	3,533,123.35			185,338.54			2,208,630

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 5.25

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 336.00 - HYDRO - ROADS, RAILROADS AND BRIDGES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 50-R5							
NET SALVAGE PERCENT.. -5							
1962	87,802.68	50.00	2.00	1,843.86	3.86	0.9228	85,076
1967	219,127.95	50.00	2.00	4,601.69	6.06	0.8788	202,198
1978	4,456,677.03	50.00	2.00	93,590.22	13.92	0.7216	3,376,735
1992	62,818.00	50.00	2.00	1,319.18	27.25	0.4550	30,011
1996	448,798.01	50.00	2.00	9,424.76	31.25	0.3750	176,714
1997	62,350.38	50.00	2.00	1,309.36	32.25	0.3550	23,241
1999	52,989.79	50.00	2.00	1,112.79	34.25	0.3150	17,526
2001	104,695.87	50.00	2.00	2,198.61	36.25	0.2750	30,231
2002	662,170.68	50.00	2.00	13,905.58	37.25	0.2550	177,296
2003	238,938.30	50.00	2.00	5,017.70	38.25	0.2350	58,958
2004	873,170.56	50.00	2.00	18,336.58	39.25	0.2150	197,118
2006	339,148.18	50.00	2.00	7,122.11	41.25	0.1750	62,318
2007	879,435.45	50.00	2.00	18,468.14	42.25	0.1550	143,128
2008	966,400.26	50.00	2.00	20,294.41	43.25	0.1350	136,987
2009	654,382.04	50.00	2.00	13,742.02	44.25	0.1150	79,017
2010	376,764.72	50.00	2.00	7,912.06	45.25	0.0950	37,582
2011	270,829.63	50.00	2.00	5,687.42	46.25	0.0750	21,328
2012	370,597.99	50.00	2.00	7,782.56	47.25	0.0550	21,402
2013	14,703.77	50.00	2.00	308.78	48.25	0.0350	540
2014	93,205.50	50.00	2.00	1,957.32	49.25	0.0150	1,468
11,235,006.79				235,935.15		4,878,874	
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.10							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 341.00 - DIESEL - STRUCTURES AND IMPROVEMENTS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 32-S2.5							
NET SALVAGE PERCENT.. -8							
1962	39,093.80	32.00	3.12	1,317.30	2.08	0.9350	39,477
1966	42,000.00	32.00	3.12	1,415.23	2.84	0.9113	41,334
1968	20,000.00	32.00	3.12	673.92	3.23	0.8991	19,420
1969	104,664.09	32.00	3.12	3,526.76	3.43	0.8928	100,921
1970	97,689.51	32.00	3.12	3,291.75	3.64	0.8863	93,504
1971	119,999.96	32.00	3.12	4,043.52	3.86	0.8794	113,968
1972	60,109.23	32.00	3.12	2,025.44	4.08	0.8725	56,641
1973	382,538.87	32.00	3.12	12,890.03	4.31	0.8653	357,496
1974	56,734.21	32.00	3.12	1,911.72	4.55	0.8578	52,561
1975	886,786.69	32.00	3.12	29,881.16	4.80	0.8500	814,070
1976	342,194.55	32.00	3.12	11,530.59	5.06	0.8419	311,134
1977	102,793.35	32.00	3.12	3,463.72	5.34	0.8331	92,490
1978	196,611.79	32.00	3.12	6,625.03	5.63	0.8241	174,982
1979	357,937.67	32.00	3.12	12,061.07	5.93	0.8147	314,937
1980	61,092.26	32.00	3.12	2,058.56	6.25	0.8047	53,093
1981	235,788.71	32.00	3.12	7,945.14	6.58	0.7944	202,290
1982	142,171.34	32.00	3.12	4,790.61	6.94	0.7831	120,244
1983	42,118.59	32.00	3.12	1,419.23	7.31	0.7716	35,097
1984	451,493.68	32.00	3.12	15,213.53	7.71	0.7591	370,128
1985	7,852,350.49	32.00	3.12	264,592.80	8.13	0.7459	6,325,973
1987	289,616.50	32.00	3.12	9,758.92	9.03	0.7178	224,521
1988	272,644.17	32.00	3.12	9,187.02	9.53	0.7022	206,764
1989	201,390.65	32.00	3.12	6,786.06	10.05	0.6859	149,193
1990	50,862.30	32.00	3.12	1,713.86	10.60	0.6688	36,735
1991	285,885.11	32.00	3.12	9,633.18	11.18	0.6506	200,883
1992	3,140,019.68	32.00	3.12	105,806.10	11.79	0.6316	2,141,760
1993	2,627,854.76	32.00	3.12	88,548.19	12.43	0.6116	1,735,658
1994	338,738.09	32.00	3.12	11,414.12	13.10	0.5906	216,071
1995	470,269.56	32.00	3.12	15,846.20	13.80	0.5688	288,863
1996	2,303,396.00	32.00	3.12	77,615.23	14.54	0.5456	1,357,321
1997	291,412.14	32.00	3.12	9,819.42	15.30	0.5219	164,249
1998	242,392.27	32.00	3.12	8,167.65	16.10	0.4969	130,075
1999	819,248.36	32.00	3.12	27,605.39	16.92	0.4713	416,956
2000	2,381,955.35	32.00	3.12	80,262.37	17.77	0.4447	1,143,970
2001	281,579.57	32.00	3.12	9,488.11	18.65	0.4172	126,870
2002	437,322.56	32.00	3.12	14,736.02	19.55	0.3891	183,756
2003	982,825.36	32.00	3.12	33,117.28	20.46	0.3606	382,781
2004	577,184.45	32.00	3.12	19,448.81	21.40	0.3313	206,488
2005	5,294,674.11	32.00	3.12	178,409.34	22.35	0.3016	1,724,395
2006	1,437,100.27	32.00	3.12	48,424.53	23.31	0.2716	421,480
2007	2,434,825.49	32.00	3.12	82,043.88	24.29	0.2409	633,579
2008	2,334,359.22	32.00	3.12	78,658.57	25.27	0.2103	530,214
2009	914,816.69	32.00	3.12	30,825.66	26.26	0.1794	177,228

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 341.00 - DIESEL - STRUCTURES AND IMPROVEMENTS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 32-S2.5							
NET SALVAGE PERCENT.. -8							
2010	681,890.45	32.00	3.12	22,976.98	27.25	0.1484	109,317
2011	340,180.04	32.00	3.12	11,462.71	28.25	0.1172	43,055
2012	581,613.84	32.00	3.12	19,598.06	29.25	0.0859	53,983
2013	408,097.81	32.00	3.12	13,751.26	30.25	0.0547	24,104
2014	1,622,442.81	32.00	3.12	54,669.83	31.25	0.0234	41,072
2015	565,441.37	32.00	3.12	19,053.11	31.88	0.0038	2,290
44,204,207.77				1,489,504.97	22,763,391		
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.37							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 342.00 - DIESEL - FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 30-L4							
NET SALVAGE PERCENT.. -10							
1972	3,782.73	30.00	3.33	138.56	3.51	0.8830	3,674
1973	3,695.00	30.00	3.33	135.35	3.72	0.8760	3,561
1974	57,303.04	30.00	3.33	2,099.01	3.92	0.8693	54,797
1975	1,087,428.89	30.00	3.33	39,832.52	4.14	0.8620	1,031,100
1976	262,280.11	30.00	3.33	9,607.32	4.36	0.8547	246,579
1977	23,681.59	30.00	3.33	867.46	4.58	0.8473	22,073
1984	28,487.01	30.00	3.33	1,043.48	5.79	0.8070	25,288
1988	373,407.76	30.00	3.33	13,677.93	6.73	0.7757	318,605
1989	24,848.26	30.00	3.33	910.19	7.14	0.7620	20,828
1990	77,044.52	30.00	3.33	2,822.14	7.64	0.7453	63,166
1991	20,000.00	30.00	3.33	732.60	8.22	0.7260	15,972
1992	469,665.92	30.00	3.33	17,203.86	8.87	0.7043	363,880
1993	242,924.77	30.00	3.33	8,898.33	9.57	0.6810	181,975
1994	323,365.12	30.00	3.33	11,844.86	10.32	0.6560	233,340
1995	436,023.51	30.00	3.33	15,971.54	11.11	0.6297	302,006
1996	1,008,209.36	30.00	3.33	36,930.71	11.92	0.6027	668,379
1997	80,777.84	30.00	3.33	2,958.89	12.76	0.5747	51,063
1998	86,529.16	30.00	3.33	3,169.56	13.62	0.5460	51,969
1999	190,023.76	30.00	3.33	6,960.57	14.51	0.5163	107,926
2000	1,434,317.45	30.00	3.33	52,539.05	15.42	0.4860	766,786
2001	136,239.78	30.00	3.33	4,990.46	16.35	0.4550	68,188
2002	181,529.55	30.00	3.33	6,649.43	17.31	0.4230	84,466
2003	198,424.76	30.00	3.33	7,268.30	18.28	0.3907	85,270
2004	642,482.18	30.00	3.33	23,534.12	19.26	0.3580	253,009
2005	89,917.03	30.00	3.33	3,293.66	20.25	0.3250	32,145
2006	652,323.48	30.00	3.33	23,894.61	21.25	0.2917	209,290
2007	1,000,745.77	30.00	3.33	36,657.32	22.25	0.2583	284,375
2008	567,041.37	30.00	3.33	20,770.73	23.25	0.2250	140,343
2009	1,828,080.91	30.00	3.33	66,962.60	24.25	0.1917	385,427
2010	1,099,329.84	30.00	3.33	40,268.45	25.25	0.1583	191,463
2011	399,139.29	30.00	3.33	14,620.47	26.25	0.1250	54,882
2013	3,252,355.12	30.00	3.33	119,133.77	28.25	0.0583	208,681
2014	7,022,711.41	30.00	3.33	257,241.92	29.25	0.0250	193,125
2015	294,507.17	30.00	3.33	10,787.80	29.88	0.0040	1,296
23,598,623.46				864,417.57	6,724,927		

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.66

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 343.00 - DIESEL - PRIME MOVERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 23-R3 NET SALVAGE PERCENT.. -8							
1967	97,324.38	23.00				1.0000	105,110
1971	621,789.37	23.00				1.0000	671,533
1972	750,091.47	23.00				1.0000	810,099
1973	2,553.27	23.00				1.0000	2,758
1974	71,220.15	23.00				1.0000	76,918
1976	2,854,193.16	23.00	4.35	134,089.99	0.06	0.9974	3,074,483
1977	10,692.21	23.00	4.35	502.32	0.28	0.9878	11,407
1978	161,361.29	23.00	4.35	7,580.75	0.50	0.9783	170,482
1980	54,319.04	23.00	4.35	2,551.91	0.99	0.9570	56,140
1982	359,164.94	23.00	4.35	16,873.57	1.50	0.9348	362,599
1983	222,276.82	23.00	4.35	10,442.57	1.76	0.9235	221,690
1984	757,269.14	23.00	4.35	35,576.50	2.02	0.9122	746,019
1985	237,363.09	23.00	4.35	11,151.32	2.28	0.9009	230,940
1987	458,190.67	23.00	4.35	21,525.80	2.84	0.8765	433,742
1988	608,936.67	23.00	4.35	28,607.84	3.16	0.8626	567,297
1989	3,146,645.99	23.00	4.35	147,829.43	3.50	0.8478	2,881,247
1990	1,445,002.95	23.00	4.35	67,886.24	3.88	0.8313	1,297,329
1991	754,570.39	23.00	4.35	35,449.72	4.30	0.8130	662,576
1992	3,936,420.21	23.00	4.35	184,933.02	4.76	0.7930	3,371,478
1993	3,343,750.93	23.00	4.35	157,089.42	5.26	0.7713	2,785,358
1994	717,562.16	23.00	4.35	33,711.07	5.80	0.7478	579,544
1995	256,437.59	23.00	4.35	12,047.44	6.38	0.7226	200,129
1996	1,770,368.29	23.00	4.35	83,171.90	7.00	0.6957	1,330,081
1997	92,659.95	23.00	4.35	4,353.16	7.65	0.6674	66,788
1998	78,351.88	23.00	4.35	3,680.97	8.34	0.6374	53,936
1999	3,855,594.23	23.00	4.35	181,135.82	9.05	0.6065	2,525,575
2000	1,000,239.71	23.00	4.35	46,991.26	9.79	0.5744	620,447
2001	800,108.33	23.00	4.35	37,589.09	10.56	0.5409	467,375
2002	633,483.22	23.00	4.35	29,761.04	11.35	0.5065	346,542
2003	1,197,923.46	23.00	4.35	56,278.44	12.17	0.4709	609,192
2004	967,641.60	23.00	4.35	45,459.80	13.00	0.4348	454,368
2005	2,979,976.44	23.00	4.35	139,999.29	13.86	0.3974	1,278,950
2006	3,800,112.24	23.00	4.35	178,529.27	14.73	0.3596	1,475,719
2007	4,616,348.19	23.00	4.35	216,876.04	15.62	0.3209	1,599,747
2008	948,136.91	23.00	4.35	44,543.47	16.54	0.2809	287,607
2009	561,071.03	23.00	4.35	26,359.12	17.46	0.2409	145,957
2010	1,029,702.77	23.00	4.35	48,375.44	18.40	0.2000	222,416
2011	2,773,680.58	23.00	4.35	130,307.51	19.35	0.1587	475,398
2012	309,178.46	23.00	4.35	14,525.20	20.31	0.1170	39,054

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 343.00 - DIESEL - PRIME MOVERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 23-R3							
NET SALVAGE PERCENT.. -8							
2013	9,502,631.28	23.00	4.35	446,433.62	21.28	0.0748	767,455
2014	4,529,319.79	23.00	4.35	212,787.44	22.26	0.0322	157,365
2015	993,358.80	23.00	4.35	46,668.00	22.88	0.0052	5,600
	63,307,023.05			2,901,674.79			32,248,450
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.58							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 344.00 - DIESEL - GENERATORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 28-R4							
NET SALVAGE PERCENT.. -5							
1984	40,659.45	28.00	3.57	1,524.12	3.01	0.8925	38,103
1985	366,859.54	28.00	3.57	13,751.73	3.36	0.8800	338,978
1989	227,611.50	28.00	3.57	8,532.02	5.29	0.8111	193,839
1992	127,214.34	28.00	3.57	4,768.63	7.25	0.7411	98,988
1993	19,337.28	28.00	3.57	724.86	7.96	0.7157	14,532
1994	597,773.11	28.00	3.57	22,407.53	8.70	0.6893	432,641
1995	711,359.95	28.00	3.57	26,665.33	9.46	0.6621	494,571
1996	749,212.90	28.00	3.57	28,084.25	10.25	0.6339	498,696
1997	444,438.49	28.00	3.57	16,659.78	11.07	0.6046	282,162
1998	132,804.98	28.00	3.57	4,978.19	11.91	0.5746	80,131
1999	180,163.87	28.00	3.57	6,753.44	12.77	0.5439	102,896
2000	291,597.31	28.00	3.57	10,930.53	13.66	0.5121	156,806
2001	162,390.25	28.00	3.57	6,087.20	14.56	0.4800	81,845
2002	328,224.97	28.00	3.57	12,303.51	15.49	0.4468	153,980
2003	20,098.57	28.00	3.57	753.39	16.43	0.4132	8,720
2004	214,130.05	28.00	3.57	8,026.66	17.38	0.3793	85,278
2005	713,658.03	28.00	3.57	26,751.47	18.34	0.3450	258,523
2006	1,390,560.58	28.00	3.57	52,125.16	19.32	0.3100	452,627
2007	530,917.26	28.00	3.57	19,901.43	20.30	0.2750	153,302
2011	423,951.83	28.00	3.57	15,891.83	24.26	0.1336	59,459
2013	60,530.80	28.00	3.57	2,269.00	26.25	0.0625	3,972
2014	666,050.11	28.00	3.57	24,966.89	27.25	0.0268	18,736
2015	409,907.55	28.00	3.57	15,365.38	27.88	0.0043	1,846
	8,809,452.72			330,222.33			4,010,631

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.75

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 345.00 - DIESEL - ACCESSORY ELECTRIC EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 24-L3							
NET SALVAGE PERCENT.. -5							
1966	6,666.67	24.00	4.17	291.90	1.66	0.9308	6,516
1968	50,187.82	24.00	4.17	2,197.47	2.06	0.9142	48,174
1972	12,000.00	24.00	4.17	525.42	2.91	0.8788	11,072
1973	16,790.60	24.00	4.17	735.18	3.13	0.8696	15,331
1974	19,347.93	24.00	4.17	847.15	3.36	0.8600	17,471
1975	60,656.50	24.00	4.17	2,655.84	3.59	0.8504	54,163
1976	179,743.38	24.00	4.17	7,870.06	3.83	0.8404	158,613
1977	593,111.48	24.00	4.17	25,969.39	4.07	0.8304	517,158
1978	51,123.62	24.00	4.17	2,238.45	4.32	0.8200	44,017
1979	64,232.15	24.00	4.17	2,812.40	4.57	0.8096	54,601
1980	28,168.55	24.00	4.17	1,233.36	4.83	0.7988	23,625
1982	37,492.30	24.00	4.17	1,641.60	5.35	0.7771	30,591
1983	355,994.26	24.00	4.17	15,587.21	5.60	0.7667	286,577
1984	20,329.72	24.00	4.17	890.14	5.86	0.7558	16,134
1985	10,175.64	24.00	4.17	445.54	6.10	0.7458	7,969
1988	76,994.43	24.00	4.17	3,371.20	6.73	0.7196	58,174
1989	1,964,950.92	24.00	4.17	86,035.38	6.91	0.7121	1,469,162
1990	91,950.86	24.00	4.17	4,026.07	7.08	0.7050	68,067
1991	760,934.24	24.00	4.17	33,317.51	7.25	0.6979	557,625
1992	837,822.02	24.00	4.17	36,684.04	7.42	0.6908	607,732
1993	259,780.61	24.00	4.17	11,374.49	7.62	0.6825	186,165
1994	597,773.14	24.00	4.17	26,173.50	7.86	0.6725	422,103
1995	380,163.73	24.00	4.17	16,645.47	8.14	0.6608	263,785
1996	922,827.56	24.00	4.17	40,406.00	8.48	0.6467	626,603
1997	1,692,084.24	24.00	4.17	74,087.91	8.89	0.6296	1,118,568
1998	929,384.63	24.00	4.17	40,693.11	9.37	0.6096	594,861
1999	386,199.02	24.00	4.17	16,909.72	9.93	0.5863	237,730
2000	470,317.44	24.00	4.17	20,592.85	10.56	0.5600	276,547
2001	421,085.12	24.00	4.17	18,437.21	11.26	0.5308	234,701
2002	563,521.83	24.00	4.17	24,673.80	12.02	0.4992	295,358
2003	562,518.05	24.00	4.17	24,629.85	12.83	0.4654	274,898
2004	94,923.63	24.00	4.17	4,156.23	13.68	0.4300	42,858
2005	1,335,271.49	24.00	4.17	58,464.86	14.56	0.3933	551,462
2006	1,182,077.20	24.00	4.17	51,757.25	15.46	0.3558	441,649
2007	1,974,449.50	24.00	4.17	86,451.27	16.38	0.3175	658,232
2008	588,373.78	24.00	4.17	25,761.95	17.33	0.2779	171,697
2009	140,806.90	24.00	4.17	6,165.23	18.29	0.2379	35,176
2010	1,104,053.63	24.00	4.17	48,340.99	19.27	0.1971	228,466
2011	962,030.37	24.00	4.17	42,122.50	20.25	0.1563	157,833
2012	708,470.12	24.00	4.17	31,020.36	21.25	0.1146	85,235

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 345.00 - DIESEL - ACCESSORY ELECTRIC EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 24-L3							
NET SALVAGE PERCENT.. -5							
2013	1,391,072.55	24.00	4.17	60,908.11	22.25	0.0729	106,509
2014	1,625,082.26	24.00	4.17	71,154.23	23.25	0.0313	53,323
2015	1,498,550.17	24.00	4.17	65,614.02	23.87	0.0054	8,528
	25,029,490.06			1,095,916.22			11,125,059
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.38							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 346.00 - DIESEL- MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 20-R4							
NET SALVAGE PERCENT.. 0							
1973	19,090.00	20.00				1.0000	19,090
1978	3,349.84	20.00				1.0000	3,350
1980	43,537.56	20.00				1.0000	43,538
1983	125,009.05	20.00				1.0000	125,009
1985	15,301.54	20.00	5.00	765.08	0.16	0.9920	15,179
1988	3,755.54	20.00	5.00	187.78	0.82	0.9590	3,602
1989	44,557.48	20.00	5.00	2,227.87	1.07	0.9465	42,174
1991	404,706.57	20.00	5.00	20,235.33	1.60	0.9200	372,330
1992	95,430.42	20.00	5.00	4,771.52	1.90	0.9050	86,365
1993	5,342.15	20.00	5.00	267.11	2.22	0.8890	4,749
1995	21,032.67	20.00	5.00	1,051.63	3.05	0.8475	17,825
1996	378,199.59	20.00	5.00	18,909.98	3.57	0.8215	310,691
1997	10,967.09	20.00	5.00	548.35	4.18	0.7910	8,675
1998	156,585.87	20.00	5.00	7,829.29	4.84	0.7580	118,692
1999	20,154.65	20.00	5.00	1,007.73	5.53	0.7235	14,582
2001	26,108.69	20.00	5.00	1,305.43	7.04	0.6480	16,918
2002	1,620.49	20.00	5.00	81.02	7.84	0.6080	985
2004	9,046.80	20.00	5.00	452.34	9.56	0.5220	4,722
2005	15,462.40	20.00	5.00	773.12	10.47	0.4765	7,368
2006	111,026.64	20.00	5.00	5,551.33	11.40	0.4300	47,741
2007	55,033.11	20.00	5.00	2,751.66	12.35	0.3825	21,050
2008	199,582.25	20.00	5.00	9,979.11	13.31	0.3345	66,760
2009	153,070.04	20.00	5.00	7,653.50	14.29	0.2855	43,701
2011	10,183.30	20.00	5.00	509.16	16.26	0.1870	1,904
2013	29,495.79	20.00	5.00	1,474.79	18.25	0.0875	2,581
2014	79,653.97	20.00	5.00	3,982.70	19.25	0.0375	2,987
2015	86,769.15	20.00	5.00	4,338.46	19.88	0.0060	521
	2,124,072.65			96,654.29			1,403,089
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.55							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 351.00 - TRANSMISSION - CLEARING LAND AND LAND RIGHTS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 65-SQUARE							
NET SALVAGE PERCENT.. 0							
1962	25,569.65	65.00	1.54	393.77	12.25	0.8115	20,751
1967	191,356.61	65.00	1.54	2,946.89	17.25	0.7346	140,574
1969	79,875.05	65.00	1.54	1,230.08	19.25	0.7039	56,220
1971	13,042.45	65.00	1.54	200.85	21.25	0.6731	8,779
1973	3,779.33	65.00	1.54	58.20	23.25	0.6423	2,428
1976	9,186.47	65.00	1.54	141.47	26.25	0.5962	5,477
1978	105,026.18	65.00	1.54	1,617.40	28.25	0.5654	59,380
1980	7,871.37	65.00	1.54	121.22	30.25	0.5346	4,208
1990	1,993,001.56	65.00	1.54	30,692.22	40.25	0.3808	758,875
1998	66,112.97	65.00	1.54	1,018.14	48.25	0.2577	17,037
1999	2,402.53	65.00	1.54	37.00	49.25	0.2423	582
2000	625,140.33	65.00	1.54	9,627.16	50.25	0.2269	141,857
	3,122,364.50			48,084.40			1,216,168

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.54

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 352.00 - TRANSMISSION - STRUCTURES AND IMPROVEMENTS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 40-R4							
NET SALVAGE PERCENT.. 0							
1990	2,842,032.30	40.00	2.50	71,050.81	16.31	0.5923	1,683,194
1996	5,611.24	40.00	2.50	140.28	21.63	0.4593	2,577
1998	143,082.02	40.00	2.50	3,577.05	23.50	0.4125	59,021
1999	49,150.23	40.00	2.50	1,228.76	24.45	0.3888	19,107
2000	53,948.06	40.00	2.50	1,348.70	25.41	0.3648	19,678
2001	105,592.19	40.00	2.50	2,639.80	26.38	0.3405	35,954
2002	108,598.45	40.00	2.50	2,714.96	27.35	0.3163	34,344
2003	11,111.78	40.00	2.50	277.79	28.33	0.2918	3,242
2004	2,631.09	40.00	2.50	65.78	29.31	0.2673	703
2008	98,682.90	40.00	2.50	2,467.07	33.27	0.1683	16,603
2009	376,740.24	40.00	2.50	9,418.51	34.26	0.1435	54,062
2012	3,381.44	40.00	2.50	84.54	37.25	0.0688	232
	3,800,561.94			95,014.05			1,928,717
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.50							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 353.00 - TRANSMISSION - STATION EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 29-R2.5							
NET SALVAGE PERCENT.. -5							
1962	25,569.65	29.00	3.45	926.26	0.29	0.9900	26,580
1967	656,100.65	29.00	3.45	23,767.25	1.62	0.9441	650,423
1969	79,875.05	29.00	3.45	2,893.47	2.10	0.9276	77,796
1971	178,977.61	29.00	3.45	6,483.46	2.54	0.9124	171,466
1972	65,510.13	29.00	3.45	2,373.10	2.76	0.9048	62,239
1973	209,885.32	29.00	3.45	7,603.10	2.99	0.8969	197,658
1974	10,538.58	29.00	3.45	381.76	3.21	0.8893	9,841
1976	9,186.47	29.00	3.45	332.78	3.69	0.8728	8,418
1977	26,973.14	29.00	3.45	977.10	3.94	0.8641	24,474
1978	728,988.32	29.00	3.45	26,407.60	4.20	0.8552	654,579
1979	609,535.69	29.00	3.45	22,080.43	4.47	0.8459	541,361
1980	7,871.37	29.00	3.45	285.14	4.77	0.8355	6,906
1982	36,852.75	29.00	3.45	1,334.99	5.42	0.8131	31,463
1983	315,205.70	29.00	3.45	11,418.33	5.78	0.8007	265,001
1985	17,592.98	29.00	3.45	637.31	6.59	0.7728	14,275
1986	52,363.07	29.00	3.45	1,896.85	7.05	0.7569	41,615
1988	47,339.47	29.00	3.45	1,714.87	8.04	0.7228	35,926
1989	55,291.93	29.00	3.45	2,002.95	8.58	0.7041	40,880
1990	2,243,001.56	29.00	3.45	81,252.73	9.15	0.6845	1,612,054
1991	53,223.90	29.00	3.45	1,928.04	9.74	0.6641	37,116
1993	31,872.46	29.00	3.45	1,154.58	11.00	0.6207	20,772
1995	165,101.64	29.00	3.45	5,980.81	12.35	0.5741	99,531
1996	206,765.12	29.00	3.45	7,490.07	13.06	0.5497	119,333
1998	1,087,690.18	29.00	3.45	39,401.58	14.52	0.4993	570,249
1999	511,197.72	29.00	3.45	18,518.14	15.28	0.4731	253,940
2000	765,815.35	29.00	3.45	27,741.66	16.06	0.4462	358,800
2001	399,840.01	29.00	3.45	14,484.20	16.85	0.4190	175,897
2002	394,972.72	29.00	3.45	14,307.89	17.66	0.3910	162,168
2003	2,107,249.59	29.00	3.45	76,335.12	18.48	0.3628	802,647
2004	182,641.01	29.00	3.45	6,616.17	19.32	0.3338	64,012
2006	356,685.33	29.00	3.45	12,920.93	21.03	0.2748	102,929
2007	669,787.34	29.00	3.45	24,263.05	21.90	0.2448	172,183
2008	128,819.13	29.00	3.45	4,666.47	22.78	0.2145	29,011
2010	532,451.67	29.00	3.45	19,288.06	24.59	0.1521	85,018
2011	886,364.37	29.00	3.45	32,108.55	25.50	0.1207	112,324
2013	59,173.12	29.00	3.45	2,143.55	27.35	0.0569	3,535
2014	596,868.29	29.00	3.45	21,621.55	28.29	0.0245	15,342
2015	554,212.21	29.00	3.45	20,076.34	28.88	0.0041	2,409
15,067,390.60				545,816.24	7,660,171		

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.62

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 354.00 - TRANSMISSION - TOWERS AND FIXTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 65-R4							
NET SALVAGE PERCENT.. -5							
1962	117,771.53	65.00	1.54	1,904.37	16.88	0.7403	91,547
1967	955,409.05	65.00	1.54	15,448.96	20.51	0.6845	686,636
1969	399,375.23	65.00	1.54	6,457.90	22.04	0.6609	277,153
1971	65,212.26	65.00	1.54	1,054.48	23.61	0.6368	43,601
1973	18,896.68	65.00	1.54	305.56	25.24	0.6117	12,137
1976	45,932.33	65.00	1.54	742.73	27.75	0.5731	27,639
1978	525,130.89	65.00	1.54	8,491.37	29.48	0.5465	301,311
1980	39,356.86	65.00	1.54	636.40	31.25	0.5192	21,457
1990	9,965,007.83	65.00	1.54	161,134.18	40.55	0.3762	3,935,755
1993	283,043.40	65.00	1.54	4,576.81	43.44	0.3317	98,577
1994	282,185.33	65.00	1.54	4,562.94	44.42	0.3166	93,813
1995	17,010.15	65.00	1.54	275.05	45.39	0.3017	5,388
1996	337.49	65.00	1.54	5.46	46.37	0.2866	102
1997	27,441.39	65.00	1.54	443.73	47.35	0.2715	7,824
1998	704,908.72	65.00	1.54	11,398.37	48.34	0.2563	189,709
1999	111,726.39	65.00	1.54	1,806.62	49.32	0.2412	28,299
2000	1,119,962.53	65.00	1.54	18,109.79	50.31	0.2260	265,767
2001	39,989.03	65.00	1.54	646.62	51.30	0.2108	8,850
2002	39,635.18	65.00	1.54	640.90	52.29	0.1955	8,138
2003	30,995.40	65.00	1.54	501.20	53.28	0.1803	5,868
2006	190,215.10	65.00	1.54	3,075.78	56.27	0.1343	26,825
2007	153,966.97	65.00	1.54	2,489.65	57.26	0.1191	19,251
2013	93,788.37	65.00	1.54	1,516.56	63.25	0.0269	2,651
2014	70,453.73	65.00	1.54	1,139.24	64.25	0.0115	854
15,297,751.84				247,364.67	6,159,152		

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.62

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 355.00 - TRANSMISSION - POLES AND FIXTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 45-R3							
NET SALVAGE PERCENT.. -5							
1991	100,046.30	45.00	2.22	2,332.08	23.18	0.4849	50,937
1993	190,544.46	45.00	2.22	4,441.59	24.83	0.4482	89,676
1996	259,046.33	45.00	2.22	6,038.37	27.39	0.3913	106,441
1997	10,498.45	45.00	2.22	244.72	28.27	0.3718	4,098
1998	119,818.14	45.00	2.22	2,792.96	29.15	0.3522	44,312
1999	67,560.32	45.00	2.22	1,574.83	30.04	0.3324	23,583
2000	412,168.27	45.00	2.22	9,607.64	30.94	0.3124	135,217
2001	14,920.42	45.00	2.22	347.79	31.85	0.2922	4,578
2003	35,212.65	45.00	2.22	820.81	33.70	0.2511	9,284
2008	387,361.38	45.00	2.22	9,029.39	38.43	0.1460	59,382
2014	59,923.51	45.00	2.22	1,396.82	44.26	0.0164	1,034
2015	112,594.97	45.00	2.22	2,624.59	44.88	0.0027	316
	1,769,695.20			41,251.59			528,858
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.33							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 356.00 - TRANSMISSION - OVERHEAD CONDUCTORS AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 60-R4							
NET SALVAGE PERCENT.. -5							
1962	76,708.92	60.00	1.67	1,345.09	12.85	0.7858	63,294
1967	355,712.73	60.00	1.67	6,237.42	16.24	0.7293	272,404
1969	239,625.14	60.00	1.67	4,201.83	17.69	0.7052	177,425
1971	39,127.36	60.00	1.67	686.10	19.18	0.6803	27,950
1973	11,338.01	60.00	1.67	198.81	20.72	0.6547	7,794
1976	27,559.38	60.00	1.67	483.25	23.12	0.6147	17,787
1978	315,078.53	60.00	1.67	5,524.90	24.79	0.5868	194,142
1980	23,614.12	60.00	1.67	414.07	26.50	0.5583	13,844
1990	5,704,986.01	60.00	1.67	100,036.93	35.61	0.4065	2,435,031
1991	316,747.51	60.00	1.67	5,554.17	36.56	0.3907	129,931
1996	11,938.06	60.00	1.67	209.33	41.39	0.3102	3,888
1997	127,705.09	60.00	1.67	2,239.31	42.37	0.2938	39,400
1998	460,246.17	60.00	1.67	8,070.42	43.35	0.2775	134,104
2000	1,664,849.19	60.00	1.67	29,193.13	45.32	0.2447	427,706
2008	1,203,678.75	60.00	1.67	21,106.51	53.26	0.1123	141,970
2014	218,357.10	60.00	1.67	3,828.89	59.25	0.0125	2,866
10,797,272.07				189,330.16		4,089,536	
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.75							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 357.00 - TRANSMISSION - UNDERGROUND CONDUIT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 30-R5							
NET SALVAGE PERCENT.. 0							
1998	12,434.28	30.00	3.33	414.06	13.28	0.5573	6,930
	12,434.28			414.06			6,930
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.33							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 358.00 - TRANSMISSION - UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 30-R5							
NET SALVAGE PERCENT.. 0							
1998	16,343.67	30.00	3.33	544.24	13.28	0.5573	9,109
	16,343.67			544.24			9,109
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.33							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 359.00 - TRANSMISSION - ROADS AND TRAILS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 40-R2							
NET SALVAGE PERCENT.. 0							
1992	550,543.25	40.00	2.50	13,763.58	21.39	0.4653	256,140
1993	199,340.65	40.00	2.50	4,983.52	22.10	0.4475	89,205
2000	259,732.76	40.00	2.50	6,493.32	27.41	0.3148	81,751
	1,009,616.66			25,240.42			427,096
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.50							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 361.00 - DISTRIBUTION - STRUCTURES AND IMPROVEMENTS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 40-R2							
NET SALVAGE PERCENT.. 0							
1975	5,294.18	40.00	2.50	132.35	11.18	0.7205	3,814
1995	1,653.70	40.00	2.50	41.34	23.57	0.4108	679
1996	88,819.64	40.00	2.50	2,220.49	24.31	0.3923	34,840
1998	55,642.25	40.00	2.50	1,391.06	25.84	0.3540	19,697
1999	66,203.25	40.00	2.50	1,655.08	26.62	0.3345	22,145
2000	1,834.87	40.00	2.50	45.87	27.41	0.3148	578
2003	27,843.13	40.00	2.50	696.08	29.83	0.2543	7,079
2005	565,604.48	40.00	2.50	14,140.11	31.48	0.2130	120,474
2006	632.75	40.00	2.50	15.82	32.32	0.1920	121
2007	16,947.83	40.00	2.50	423.70	33.17	0.1708	2,894
	830,476.08			20,761.90			212,321
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.50							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 362.00 - DISTRIBUTION - STATION EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 25-S2.5							
NET SALVAGE PERCENT.. 0							
1967	144,317.32	25.00	4.00	5,772.69	0.41	0.9836	141,951
1972	6,463.18	25.00	4.00	258.53	1.34	0.9464	6,117
1973	241,116.14	25.00	4.00	9,644.65	1.52	0.9392	226,456
1975	3,803.80	25.00	4.00	152.15	1.90	0.9240	3,515
1985	20,428.45	25.00	4.00	817.14	4.10	0.8360	17,078
1995	2,894.09	25.00	4.00	115.76	8.05	0.6780	1,962
1996	9,760.82	25.00	4.00	390.43	8.62	0.6552	6,395
1997	2,628.04	25.00	4.00	105.12	9.22	0.6312	1,659
1998	11,606.26	25.00	4.00	464.25	9.87	0.6052	7,024
1999	519,843.66	25.00	4.00	20,793.75	10.55	0.5780	300,470
2000	114,896.20	25.00	4.00	4,595.85	11.28	0.5488	63,055
2001	17,217.19	25.00	4.00	688.69	12.05	0.5180	8,919
2002	281,371.31	25.00	4.00	11,254.85	12.85	0.4860	136,746
2003	15,604.03	25.00	4.00	624.16	13.69	0.4524	7,059
2004	6,673.85	25.00	4.00	266.95	14.56	0.4176	2,787
2005	87,808.16	25.00	4.00	3,512.33	15.46	0.3816	33,508
2008	64,854.73	25.00	4.00	2,594.19	18.30	0.2680	17,381
2009	46,635.84	25.00	4.00	1,865.43	19.27	0.2292	10,689
2010	49,982.80	25.00	4.00	1,999.31	20.26	0.1896	9,477
2013	68,782.41	25.00	4.00	2,751.30	23.25	0.0700	4,815
2014	215,968.15	25.00	4.00	8,638.73	24.25	0.0300	6,479
	1,932,656.43			77,306.26			1,013,542
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.00							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 363.00 - DISTRIBUTION - STORAGE BATTERY EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 15-R4							
NET SALVAGE PERCENT.. 0							
2006	23,230.28	15.00	6.67	1,549.46	6.57	0.5620	13,055
2007	39,050.78	15.00	6.67	2,604.69	7.45	0.5033	19,655
	62,281.06			4,154.15			32,710
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.67							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 364.00 - DISTRIBUTION - POLES, TOWERS, AND FIXTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 50-R2.5							
NET SALVAGE PERCENT.. -5							
1962	667,587.34	50.00	2.00	14,019.33	10.75	0.7850	550,259
1963	28,373.91	50.00	2.00	595.85	11.17	0.7766	23,137
1966	45,123.25	50.00	2.00	947.59	12.53	0.7494	35,506
1970	10,985.24	50.00	2.00	230.69	14.60	0.7080	8,166
1971	143,471.08	50.00	2.00	3,012.89	15.15	0.6970	104,999
1972	118,755.74	50.00	2.00	2,493.87	15.72	0.6856	85,490
1973	81,114.92	50.00	2.00	1,703.41	16.31	0.6738	57,388
1974	145,447.64	50.00	2.00	3,054.40	16.91	0.6618	101,070
1975	170,089.48	50.00	2.00	3,571.88	17.53	0.6494	115,979
1976	72,043.55	50.00	2.00	1,512.91	18.16	0.6368	48,171
1977	18,329.49	50.00	2.00	384.92	18.81	0.6238	12,006
1978	88,960.29	50.00	2.00	1,868.17	19.46	0.6108	57,054
1979	196,205.86	50.00	2.00	4,120.32	20.13	0.5974	123,074
1980	117,891.28	50.00	2.00	2,475.72	20.81	0.5838	72,266
1981	97,421.64	50.00	2.00	2,045.85	21.51	0.5698	58,286
1982	112,378.71	50.00	2.00	2,359.95	22.21	0.5558	65,583
1983	211,778.96	50.00	2.00	4,447.36	22.93	0.5414	120,390
1984	126,193.65	50.00	2.00	2,650.07	23.66	0.5268	69,803
1985	328,316.19	50.00	2.00	6,894.64	24.39	0.5122	176,572
1986	304,138.10	50.00	2.00	6,386.90	25.14	0.4972	158,778
1987	175,809.13	50.00	2.00	3,691.99	25.90	0.4820	88,977
1988	300,689.75	50.00	2.00	6,314.48	26.66	0.4668	147,380
1989	167,753.83	50.00	2.00	3,522.83	27.44	0.4512	79,475
1990	51,222.90	50.00	2.00	1,075.68	28.22	0.4356	23,428
1991	491,960.93	50.00	2.00	10,331.18	29.02	0.4196	216,748
1992	429,127.87	50.00	2.00	9,011.69	29.82	0.4036	181,856
1993	175,540.66	50.00	2.00	3,686.35	30.63	0.3874	71,405
1994	340,749.78	50.00	2.00	7,155.75	31.46	0.3708	132,668
1995	390,399.04	50.00	2.00	8,198.38	32.28	0.3544	145,275
1996	811,640.53	50.00	2.00	17,044.45	33.12	0.3376	287,710
1997	274,210.15	50.00	2.00	5,758.41	33.97	0.3206	92,307
1998	458,741.19	50.00	2.00	9,633.56	34.82	0.3036	146,238
1999	419,333.88	50.00	2.00	8,806.01	35.68	0.2864	126,102
2000	255,866.19	50.00	2.00	5,373.19	36.54	0.2692	72,323
2001	119,239.90	50.00	2.00	2,504.04	37.42	0.2516	31,501
2002	365,236.17	50.00	2.00	7,669.96	38.30	0.2340	89,739
2003	427,562.44	50.00	2.00	8,978.81	39.18	0.2164	97,151
2004	357,017.77	50.00	2.00	7,497.37	40.08	0.1984	74,374
2005	796,639.85	50.00	2.00	16,729.44	40.98	0.1804	150,900
2006	444,554.99	50.00	2.00	9,335.65	41.88	0.1624	75,806
2007	461,757.47	50.00	2.00	9,696.91	42.79	0.1442	69,915
2008	639,766.53	50.00	2.00	13,435.10	43.71	0.1258	84,507
2009	368,513.26	50.00	2.00	7,738.78	44.63	0.1074	41,557

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 364.00 - DISTRIBUTION - POLES, TOWERS, AND FIXTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 50-R2.5							
NET SALVAGE PERCENT.. -5							
2010	394,743.73	50.00	2.00	8,289.62	45.55	0.0890	36,889
2011	477,561.77	50.00	2.00	10,028.80	46.48	0.0704	35,301
2012	147,170.71	50.00	2.00	3,090.58	47.41	0.0518	8,005
2013	304,654.22	50.00	2.00	6,397.74	48.35	0.0330	10,556
2014	1,437,288.01	50.00	2.00	30,183.05	49.29	0.0142	21,430
2015	24,905.62	50.00	2.00	523.02	49.88	0.0024	63
	14,594,264.59			306,479.54			4,683,563
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.10							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 365.00 - DISTRIBUTION - OVERHEAD CONDUCTORS AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 55-R4							
NET SALVAGE PERCENT.. -5							
1962	345,078.99	55.00	1.82	6,594.46	9.17	0.8333	301,921
1963	14,186.96	55.00	1.82	271.11	9.72	0.8233	12,264
1966	22,561.62	55.00	1.82	431.15	11.52	0.7906	18,728
1970	17,504.82	55.00	1.82	334.52	14.20	0.7418	13,635
1971	59,723.34	55.00	1.82	1,141.31	14.91	0.7289	45,710
1972	59,377.87	55.00	1.82	1,134.71	15.62	0.7160	44,640
1973	50,075.67	55.00	1.82	956.95	16.35	0.7027	36,949
1974	246,921.44	55.00	1.82	4,718.67	17.09	0.6893	178,705
1975	85,044.73	55.00	1.82	1,625.20	17.85	0.6755	60,316
1976	57,726.17	55.00	1.82	1,103.15	18.62	0.6615	40,092
1977	9,164.75	55.00	1.82	175.14	19.40	0.6473	6,229
1978	46,008.82	55.00	1.82	879.23	20.20	0.6327	30,567
1979	106,213.17	55.00	1.82	2,029.73	21.01	0.6180	68,922
1980	65,074.52	55.00	1.82	1,243.57	21.83	0.6031	41,208
1981	48,710.83	55.00	1.82	930.86	22.67	0.5878	30,065
1982	56,189.36	55.00	1.82	1,073.78	23.52	0.5724	33,769
1983	102,353.82	55.00	1.82	1,955.98	24.38	0.5567	59,833
1984	67,745.40	55.00	1.82	1,294.61	25.25	0.5409	38,476
1985	165,593.42	55.00	1.82	3,164.49	26.13	0.5249	91,268
1986	146,039.01	55.00	1.82	2,790.81	27.03	0.5086	77,982
1987	117,213.73	55.00	1.82	2,239.95	27.93	0.4922	60,575
1988	141,925.38	55.00	1.82	2,712.19	28.85	0.4755	70,852
1989	58,384.04	55.00	1.82	1,115.72	29.77	0.4587	28,122
1990	8,935.77	55.00	1.82	170.76	30.70	0.4418	4,145
1991	133,536.98	55.00	1.82	2,551.89	31.64	0.4247	59,553
1992	18,634.89	55.00	1.82	356.11	32.58	0.4076	7,976
1993	47,788.64	55.00	1.82	913.24	33.54	0.3902	19,578
1994	69,701.14	55.00	1.82	1,331.99	34.49	0.3729	27,292
1995	96,101.02	55.00	1.82	1,836.49	35.46	0.3553	35,849
1996	164,227.97	55.00	1.82	3,138.40	36.42	0.3378	58,253
1997	57,286.91	55.00	1.82	1,094.75	37.40	0.3200	19,248
1998	74,248.82	55.00	1.82	1,418.89	38.37	0.3024	23,572
1999	192,312.47	55.00	1.82	3,675.09	39.35	0.2846	57,459
2000	26,487.11	55.00	1.82	506.17	40.33	0.2667	7,418
2001	19,847.13	55.00	1.82	379.28	41.32	0.2487	5,183
2002	6,691.74	55.00	1.82	127.88	42.31	0.2307	1,621
2003	159,067.08	55.00	1.82	3,039.77	43.29	0.2129	35,560
2004	117,602.65	55.00	1.82	2,247.39	44.29	0.1947	24,046
2005	96,429.82	55.00	1.82	1,842.77	45.28	0.1767	17,894
2006	103,317.60	55.00	1.82	1,974.40	46.27	0.1587	17,220
2007	161,126.10	55.00	1.82	3,079.12	47.27	0.1406	23,779
2008	171,752.68	55.00	1.82	3,282.19	48.26	0.1226	22,101
2009	86,526.01	55.00	1.82	1,653.51	49.26	0.1044	9,481

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 365.00 - DISTRIBUTION - OVERHEAD CONDUCTORS AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 55-R4							
NET SALVAGE PERCENT.. -5							
2010	79,984.54	55.00	1.82	1,528.50	50.26	0.0862	7,238
2011	100,262.84	55.00	1.82	1,916.02	51.25	0.0682	7,178
2012	23,289.28	55.00	1.82	445.06	52.25	0.0500	1,223
2013	27,756.04	55.00	1.82	530.42	53.25	0.0318	927
2014	234,982.33	55.00	1.82	4,490.51	54.25	0.0136	3,365
	4,366,715.42			83,447.89			1,887,987
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.91							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 366.00 - DISTRIBUTION - UNDERGROUND CONDUIT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 30-R5							
NET SALVAGE PERCENT.. 0							
1999	17,338.63	30.00	3.33	577.38	14.26	0.5247	9,097
2003	25,738.45	30.00	3.33	857.09	18.25	0.3917	10,081
2006	23,844.74	30.00	3.33	794.03	21.25	0.2917	6,955
2011	7,647.83	30.00	3.33	254.67	26.25	0.1250	956
2012	3,518.62	30.00	3.33	117.17	27.25	0.0917	323
2013	51,078.98	30.00	3.33	1,700.93	28.25	0.0583	2,979
	129,167.25			4,301.27			30,391
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.33							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 367.00 - DISTRIBUTION - UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 30-R5							
NET SALVAGE PERCENT.. 0							
1973	1,000.00	30.00				1.0000	1,000
1980	46,855.09	30.00	3.33	1,560.27	1.45	0.9517	44,591
1996	695.92	30.00	3.33	23.17	11.35	0.6217	433
1999	94,889.83	30.00	3.33	3,159.83	14.26	0.5247	49,786
2003	16,566.60	30.00	3.33	551.67	18.25	0.3917	6,489
2004	814.58	30.00	3.33	27.13	19.25	0.3583	292
2005	8,082.45	30.00	3.33	269.15	20.25	0.3250	2,627
2007	15,599.04	30.00	3.33	519.45	22.25	0.2583	4,030
2008	32,348.92	30.00	3.33	1,077.22	23.25	0.2250	7,279
2009	5,136.20	30.00	3.33	171.04	24.25	0.1917	984
2010	53,967.15	30.00	3.33	1,797.11	25.25	0.1583	8,545
2011	71,808.17	30.00	3.33	2,391.21	26.25	0.1250	8,976
2013	97,149.90	30.00	3.33	3,235.09	28.25	0.0583	5,667
2014	239,106.26	30.00	3.33	7,962.24	29.25	0.0250	5,978
	684,020.11			22,744.58			146,677

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.33

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 368.00 - DISTRIBUTION - LINE TRANSFORMERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 50-R5							
NET SALVAGE PERCENT.. 0							
1962	110,314.54	50.00	2.00	2,206.29	3.86	0.9228	101,798
1964	14,720.13	50.00	2.00	294.40	4.64	0.9072	13,354
1967	27,883.89	50.00	2.00	557.68	6.06	0.8788	24,504
1968	6,457.22	50.00	2.00	129.14	6.61	0.8678	5,604
1969	18,535.49	50.00	2.00	370.71	7.19	0.8562	15,870
1970	12,689.07	50.00	2.00	253.78	7.81	0.8438	10,707
1971	49,965.84	50.00	2.00	999.32	8.47	0.8306	41,502
1972	24,736.60	50.00	2.00	494.73	9.16	0.8168	20,205
1973	334,067.46	50.00	2.00	6,681.35	9.88	0.8024	268,056
1974	20,561.15	50.00	2.00	411.22	10.64	0.7872	16,186
1975	39,214.41	50.00	2.00	784.29	11.42	0.7716	30,258
1976	28,163.31	50.00	2.00	563.27	12.23	0.7554	21,275
1977	279,603.75	50.00	2.00	5,592.08	13.06	0.7388	206,571
1978	198,021.38	50.00	2.00	3,960.43	13.92	0.7216	142,892
1979	21,877.74	50.00	2.00	437.55	14.79	0.7042	15,406
1980	563.63	50.00	2.00	11.27	15.68	0.6864	387
1982	9,954.79	50.00	2.00	199.10	17.51	0.6498	6,469
1985	54,539.61	50.00	2.00	1,090.79	20.35	0.5930	32,342
1986	45,282.07	50.00	2.00	905.64	21.32	0.5736	25,974
1988	12,786.49	50.00	2.00	255.73	23.28	0.5344	6,833
1989	268,476.72	50.00	2.00	5,369.53	24.27	0.5146	138,158
1990	18,953.69	50.00	2.00	379.07	25.26	0.4948	9,378
1991	159,336.34	50.00	2.00	3,186.73	26.26	0.4748	75,653
1992	17,542.06	50.00	2.00	350.84	27.25	0.4550	7,982
1993	98,517.15	50.00	2.00	1,970.34	28.25	0.4350	42,855
1994	97,258.76	50.00	2.00	1,945.18	29.25	0.4150	40,362
1995	97,032.78	50.00	2.00	1,940.66	30.25	0.3950	38,328
1996	341,863.84	50.00	2.00	6,837.28	31.25	0.3750	128,199
1997	27,131.92	50.00	2.00	542.64	32.25	0.3550	9,632
1998	86,515.62	50.00	2.00	1,730.31	33.25	0.3350	28,983
1999	192,718.44	50.00	2.00	3,854.37	34.25	0.3150	60,706
2000	35,778.43	50.00	2.00	715.57	35.25	0.2950	10,555
2001	31,424.03	50.00	2.00	628.48	36.25	0.2750	8,642
2002	2,143.65	50.00	2.00	42.87	37.25	0.2550	547
2003	169,398.41	50.00	2.00	3,387.97	38.25	0.2350	39,809
2004	133,137.73	50.00	2.00	2,662.75	39.25	0.2150	28,625
2005	185,017.08	50.00	2.00	3,700.34	40.25	0.1950	36,078
2006	132,308.70	50.00	2.00	2,646.17	41.25	0.1750	23,154
2007	228,118.19	50.00	2.00	4,562.36	42.25	0.1550	35,358
2008	211,156.20	50.00	2.00	4,223.12	43.25	0.1350	28,506
2009	338,155.96	50.00	2.00	6,763.12	44.25	0.1150	38,888
2010	336,561.35	50.00	2.00	6,731.23	45.25	0.0950	31,973
2011	340,058.88	50.00	2.00	6,801.18	46.25	0.0750	25,504

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 368.00 - DISTRIBUTION - LINE TRANSFORMERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 50-R5							
NET SALVAGE PERCENT.. 0							
2012	359,808.13	50.00	2.00	7,196.16	47.25	0.0550	19,789
2013	514,609.92	50.00	2.00	10,292.20	48.25	0.0350	18,011
2014	590,024.42	50.00	2.00	11,800.49	49.25	0.0150	8,850
	6,322,986.97			126,459.73			1,940,718
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.00							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 369.00 - DISTRIBUTION - SERVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 55-R4							
NET SALVAGE PERCENT.. -5							
1962	118,583.43	55.00	1.82	2,266.13	9.17	0.8333	103,753
1963	4,728.98	55.00	1.82	90.37	9.72	0.8233	4,088
1966	7,520.54	55.00	1.82	143.72	11.52	0.7906	6,243
1970	1,830.88	55.00	1.82	34.99	14.20	0.7418	1,426
1971	22,960.52	55.00	1.82	438.78	14.91	0.7289	17,573
1972	19,792.62	55.00	1.82	378.24	15.62	0.7160	14,880
1973	15,882.52	55.00	1.82	303.51	16.35	0.7027	11,719
1974	24,337.99	55.00	1.82	465.10	17.09	0.6893	17,614
1975	25,826.99	55.00	1.82	493.55	17.85	0.6755	18,317
1976	13,079.36	55.00	1.82	249.95	18.62	0.6615	9,084
1977	3,054.92	55.00	1.82	58.38	19.40	0.6473	2,076
1978	15,336.30	55.00	1.82	293.08	20.20	0.6327	10,189
1979	35,404.37	55.00	1.82	676.58	21.01	0.6180	22,974
1980	20,452.94	55.00	1.82	390.86	21.83	0.6031	12,952
1981	16,236.92	55.00	1.82	310.29	22.67	0.5878	10,022
1982	18,729.79	55.00	1.82	357.93	23.52	0.5724	11,256
1983	27,599.64	55.00	1.82	527.43	24.38	0.5567	16,134
1984	25,416.41	55.00	1.82	485.71	25.25	0.5409	14,435
1985	117,354.54	55.00	1.82	2,242.65	26.13	0.5249	64,681
1986	43,504.95	55.00	1.82	831.38	27.03	0.5086	23,231
1987	34,861.51	55.00	1.82	666.20	27.93	0.4922	18,016
1988	114,746.38	55.00	1.82	2,192.80	28.85	0.4755	57,284
1989	138,483.53	55.00	1.82	2,646.42	29.77	0.4587	66,703
1990	373.57	55.00	1.82	7.14	30.70	0.4418	173
1991	350,003.00	55.00	1.82	6,688.56	31.64	0.4247	156,090
1992	131,540.87	55.00	1.82	2,513.75	32.58	0.4076	56,302
1993	26,903.95	55.00	1.82	514.13	33.54	0.3902	11,022
1996	911.99	55.00	1.82	17.43	36.42	0.3378	323
1997	4,132.76	55.00	1.82	78.98	37.40	0.3200	1,389
1998	2,800.00	55.00	1.82	53.51	38.37	0.3024	889
2000	13,695.63	55.00	1.82	261.72	40.33	0.2667	3,836
2001	12,514.46	55.00	1.82	239.15	41.32	0.2487	3,268
2002	2,499.90	55.00	1.82	47.77	42.31	0.2307	606
2003	8,149.13	55.00	1.82	155.73	43.29	0.2129	1,822
2004	2,638.51	55.00	1.82	50.42	44.29	0.1947	539
2005	10,505.21	55.00	1.82	200.75	45.28	0.1767	1,949
2006	4,464.39	55.00	1.82	85.31	46.27	0.1587	744
2007	10,055.43	55.00	1.82	192.16	47.27	0.1406	1,484
2008	9,073.86	55.00	1.82	173.40	48.26	0.1226	1,168
2009	40,028.21	55.00	1.82	764.94	49.26	0.1044	4,386
2010	127,527.79	55.00	1.82	2,437.06	50.26	0.0862	11,540
2011	481,854.97	55.00	1.82	9,208.25	51.25	0.0682	34,496
2012	114,879.14	55.00	1.82	2,195.34	52.25	0.0500	6,031

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 369.00 - DISTRIBUTION - SERVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 55-R4							
NET SALVAGE PERCENT.. -5							
2013	116,841.08	55.00	1.82	2,232.83	53.25	0.0318	3,904
2014	102,301.44	55.00	1.82	1,954.98	54.25	0.0136	1,465
2015	6,608.01	55.00	1.82	126.28	54.88	0.0022	15
	2,446,029.33			46,743.64			838,091
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.91							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 370.00 - DISTRIBUTION - METERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 18-L1							
NET SALVAGE PERCENT.. 0							
1972	2,923.03	18.00	5.56	162.52	2.56	0.8578	2,507
1973	1,085.00	18.00	5.56	60.33	2.74	0.8478	920
1975	2,404.32	18.00	5.56	133.68	3.12	0.8267	1,988
1976	19,239.45	18.00	5.56	1,069.71	3.31	0.8161	15,702
1977	44,414.67	18.00	5.56	2,469.46	3.51	0.8050	35,754
1978	35,705.19	18.00	5.56	1,985.21	3.71	0.7939	28,346
1979	18,379.09	18.00	5.56	1,021.88	3.92	0.7822	14,376
1980	106,025.00	18.00	5.56	5,894.99	4.13	0.7706	81,699
1981	20,867.64	18.00	5.56	1,160.24	4.34	0.7589	15,836
1982	53,300.20	18.00	5.56	2,963.49	4.56	0.7467	39,798
1991	1,789.23	18.00	5.56	99.48	6.75	0.6250	1,118
1994	6,415.40	18.00	5.56	356.70	7.59	0.5783	3,710
1995	5,358.32	18.00	5.56	297.92	7.89	0.5617	3,010
1996	5,247.92	18.00	5.56	291.78	8.20	0.5444	2,857
1997	5,538.34	18.00	5.56	307.93	8.51	0.5272	2,920
1998	5,124.12	18.00	5.56	284.90	8.83	0.5094	2,610
1999	97,452.67	18.00	5.56	5,418.37	9.16	0.4911	47,860
2000	28,072.53	18.00	5.56	1,560.83	9.50	0.4722	13,256
2001	80,142.65	18.00	5.56	4,455.93	9.85	0.4528	36,287
2002	32,318.18	18.00	5.56	1,796.89	10.22	0.4322	13,969
2003	67,733.15	18.00	5.56	3,765.96	10.59	0.4117	27,884
2004	76,434.83	18.00	5.56	4,249.78	10.97	0.3906	29,852
2005	37,166.11	18.00	5.56	2,066.44	11.38	0.3678	13,669
2006	173,554.94	18.00	5.56	9,649.65	11.81	0.3439	59,684
2007	291,966.42	18.00	5.56	16,233.33	12.28	0.3178	92,781
2008	66,263.48	18.00	5.56	3,684.25	12.81	0.2883	19,106
2009	123,258.55	18.00	5.56	6,853.18	13.40	0.2556	31,500
2010	100,614.39	18.00	5.56	5,594.16	14.05	0.2194	22,079
2011	117,736.49	18.00	5.56	6,546.15	14.78	0.1789	21,062
2012	112,176.09	18.00	5.56	6,236.99	15.56	0.1356	15,207
2013	81,620.08	18.00	5.56	4,538.08	16.41	0.0883	7,210
2014	101,329.97	18.00	5.56	5,633.95	17.30	0.0389	3,941
	1,921,657.45			106,844.16			708,498

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 5.56

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 371.00 - DISTRIBUTION - INSTALLATIONS ON CUSTOMER PREMISES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 18-L1							
NET SALVAGE PERCENT.. 0							
1996	8,024.38	18.00	5.56	446.16	8.20	0.5444	4,369
2000	2,746.14	18.00	5.56	152.69	9.50	0.4722	1,297
	10,770.52			598.85			5,666
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 5.56							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 373.00 - DISTRIBUTION - STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 48-R4							
NET SALVAGE PERCENT.. -5							
1966	3,527.95	48.00	2.08	77.05	6.69	0.8606	3,188
1969	2,735.99	48.00	2.08	59.75	8.16	0.8300	2,384
1972	4,384.54	48.00	2.08	95.76	9.93	0.7931	3,651
1973	2,691.53	48.00	2.08	58.78	10.57	0.7798	2,204
1976	7,754.48	48.00	2.08	169.36	12.61	0.7373	6,003
1978	694.23	48.00	2.08	15.16	14.04	0.7075	516
1979	155.29	48.00	2.08	3.39	14.78	0.6921	113
1980	361.26	48.00	2.08	7.89	15.53	0.6765	257
1982	113.22	48.00	2.08	2.47	17.09	0.6440	77
1984	2,988.35	48.00	2.08	65.27	18.70	0.6104	1,915
1985	15,385.99	48.00	2.08	336.03	19.53	0.5931	9,582
1986	29,507.21	48.00	2.08	644.44	20.38	0.5754	17,828
1988	5,184.61	48.00	2.08	113.23	22.11	0.5394	2,936
1989	643.36	48.00	2.08	14.05	23.00	0.5208	352
1991	11,050.89	48.00	2.08	241.35	24.81	0.4831	5,606
1992	5,465.07	48.00	2.08	119.36	25.72	0.4642	2,664
1993	2,031.33	48.00	2.08	44.36	26.65	0.4448	949
1994	2,206.86	48.00	2.08	48.20	27.59	0.4252	985
1996	2,334.08	48.00	2.08	50.98	29.49	0.3856	945
1997	4,057.08	48.00	2.08	88.61	30.45	0.3656	1,558
1998	20,927.88	48.00	2.08	457.06	31.41	0.3456	7,595
1999	6,427.30	48.00	2.08	140.37	32.38	0.3254	2,196
2000	2,197.50	48.00	2.08	47.99	33.36	0.3050	704
2003	18,717.77	48.00	2.08	408.80	36.31	0.2435	4,786
2004	79,940.24	48.00	2.08	1,745.89	37.29	0.2231	18,728
2005	170,943.83	48.00	2.08	3,733.41	38.28	0.2025	36,347
2006	1,639.10	48.00	2.08	35.80	39.28	0.1817	313
2007	80,623.59	48.00	2.08	1,760.82	40.27	0.1610	13,633
2008	73,612.29	48.00	2.08	1,607.69	41.26	0.1404	10,853
2009	138,124.02	48.00	2.08	3,016.63	42.26	0.1196	17,343
2010	56,721.38	48.00	2.08	1,238.79	43.26	0.0988	5,881
2011	33,371.87	48.00	2.08	728.84	44.26	0.0779	2,730
2012	19,434.88	48.00	2.08	424.46	45.25	0.0573	1,169
2013	122,562.75	48.00	2.08	2,676.77	46.25	0.0365	4,692
2014	399,512.66	48.00	2.08	8,725.36	47.25	0.0156	6,552
2015	110,488.12	48.00	2.08	2,413.06	47.88	0.0025	290
	1,438,518.50			31,417.23			197,525

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.18

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 382.00 - COMPUTER HARDWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
2010	2,480,319.16	5.00	20.00	496,063.83	0.25	0.9500	2,356,303
2011	1,155,805.27	5.00	20.00	231,161.05	1.25	0.7500	866,854
2012	224,105.04	5.00	20.00	44,821.01	2.25	0.5500	123,258
2013	75,768.18	5.00	20.00	15,153.64	3.25	0.3500	26,519
2014	546,058.71	5.00	20.00	109,211.74	4.25	0.1500	81,909
2015	73,309.00	5.00	20.00	14,661.80	4.88	0.0240	1,759
	4,555,365.36			911,073.07			3,456,602
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 20.00							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 383.00 - COMPUTER SOFTWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 10-SQUARE							
NET SALVAGE PERCENT.. 0							
2005	933,490.62	10.00	10.00	93,349.06	0.25	0.9750	910,153
2006	398,749.14	10.00	10.00	39,874.91	1.25	0.8750	348,905
2007	1,606,293.00	10.00	10.00	160,629.30	2.25	0.7750	1,244,877
2012	204,795.55	10.00	10.00	20,479.56	7.25	0.2750	56,319
2013	36,670.03	10.00	10.00	3,667.00	8.25	0.1750	6,417
2014	570,962.83	10.00	10.00	57,096.28	9.25	0.0750	42,822
2015	8,302.80	10.00	10.00	830.28	9.88	0.0120	100
	3,759,263.97			375,926.39			2,609,593
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 10.00							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 390.02 - STRUCTURES AND IMPROVEMENTS - OTHER SMALL STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL -- AMOUNT (5)	EXP. (6)	--ACCRUED DEPREC. -- FACTOR (7)	AMOUNT (8)
ACCOUNT 390.01 - GENERAL PLANT - STRUCTURES AND IMPROVEMENTS HAY RIVER BUILDING SURVIVOR CURVE.. IOWA 65-R1.5 NET SALVAGE PERCENT.. +15							
1989	2,623,609.07	65.00	1.54	34,343.04	44.95	0.3085	687,887
1991	9,640.00	65.00	1.54	126.19	46.41	0.2860	2,343
1992	357,223.49	65.00	1.54	4,676.06	47.15	0.2746	83,386
1993	113,842.70	65.00	1.54	1,490.20	47.90	0.2631	25,457
1994	5,514.25	65.00	1.54	72.18	48.65	0.2515	1,179
1995	144,862.55	65.00	1.54	1,896.25	49.40	0.2400	29,552
1996	59,338.77	65.00	1.54	776.74	50.15	0.2285	11,523
1997	11,175.00	65.00	1.54	146.28	50.91	0.2168	2,059
1999	29,279.34	65.00	1.54	383.27	52.44	0.1932	4,809
2000	330,993.76	65.00	1.54	4,332.71	53.21	0.1814	51,030
2001	300,183.82	65.00	1.54	3,929.41	53.99	0.1694	43,218
2002	189,027.51	65.00	1.54	2,474.37	54.77	0.1574	25,287
2003	134,278.30	65.00	1.54	1,757.70	55.55	0.1454	16,593
2005	2,181.86	65.00	1.54	28.56	57.12	0.1212	225
2006	209,426.88	65.00	1.54	2,741.40	57.91	0.1091	19,418
2007	13,559.39	65.00	1.54	177.49	58.71	0.0968	1,115
2008	58,844.41	65.00	1.54	770.27	59.51	0.0845	4,224
2009	135,871.60	65.00	1.54	1,778.56	60.31	0.0722	8,333
2011	39,215.42	65.00	1.54	513.33	61.93	0.0472	1,574
2012	13,294.91	65.00	1.54	174.03	62.74	0.0348	393
2013	40,337.83	65.00	1.54	528.02	63.56	0.0222	759
2014	33,596.19	65.00	1.54	439.77	64.38	0.0095	272
2015	45,048.50	65.00	1.54	589.68	64.90	0.0015	59
4,900,345.55				64,145.51	1,020,695		

ACCOUNT 390.02 - GENERAL PLANT - STRUCTURES AND IMPROVEMENTS OTHER SMALL BUILDINGS
SURVIVOR CURVE.. IOWA 25-R1.5
NET SALVAGE PERCENT.. +5

1962	75,183.56	25.00				1.0000	71,424
1965	9,784.62	25.00	4.00	371.82	0.19	0.9924	9,225
1967	297,702.91	25.00	4.00	11,312.71	0.83	0.9668	273,428
1968	5,309.85	25.00	4.00	201.77	1.17	0.9532	4,808
1971	3,000.00	25.00	4.00	114.00	1.99	0.9204	2,623
1972	48,995.51	25.00	4.00	1,861.83	2.22	0.9112	42,412
1974	12,329.17	25.00	4.00	468.51	2.69	0.8924	10,452
1975	31,094.72	25.00	4.00	1,181.60	2.94	0.8824	26,066
1976	201,769.67	25.00	4.00	7,667.25	3.20	0.8720	167,146
1977	185,464.74	25.00	4.00	7,047.66	3.48	0.8608	151,666



NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 390.02 STRUCTURES AND IMPROVEMENTS - OTHER SMALL STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
ACCOUNT 390.02 - GENERAL PLANT - STRUCTURES AND IMPROVEMENTS OTHER SMALL BUILDINGS							
SURVIVOR CURVE.. IOWA 25-R1.5							
NET SALVAGE PERCENT.. +5							
1978	12,460.15	25.00	4.00	473.49	3.76	0.8496	10,057
1980	5,201.83	25.00	4.00	197.67	4.35	0.8260	4,082
1981	2,572.81	25.00	4.00	97.77	4.66	0.8136	1,989
1982	272,111.78	25.00	4.00	10,340.25	4.99	0.8004	206,908
1984	1.00	25.00	4.00	0.04	5.67	0.7732	1
1985	100,658.50	25.00	4.00	3,825.02	6.04	0.7584	72,522
1987	22,632.50	25.00	4.00	860.04	6.82	0.7272	15,635
1988	123,836.00	25.00	4.00	4,705.77	7.25	0.7100	83,527
1989	36,997.62	25.00	4.00	1,405.91	7.69	0.6924	24,336
1991	6,267.94	25.00	4.00	238.18	8.64	0.6544	3,897
1993	31,661.85	25.00	4.00	1,203.15	9.67	0.6132	18,444
1995	69,030.00	25.00	4.00	2,623.14	10.79	0.5684	37,275
1996	85,652.52	25.00	4.00	3,254.80	11.37	0.5452	44,363
1997	89,760.26	25.00	4.00	3,410.89	11.98	0.5208	44,410
1998	304,328.87	25.00	4.00	11,564.50	12.60	0.4960	143,400
1999	932,856.82	25.00	4.00	35,448.56	13.24	0.4704	416,875
2000	3,624.02	25.00	4.00	137.71	13.90	0.4440	1,529
2001	1,434.78	25.00	4.00	54.52	14.57	0.4172	569
2002	66,767.93	25.00	4.00	2,537.18	15.26	0.3896	24,712
2003	523,522.14	25.00	4.00	19,893.84	15.96	0.3616	179,840
2004	404,991.69	25.00	4.00	15,389.68	16.67	0.3332	128,196
2005	367,414.65	25.00	4.00	13,961.76	17.40	0.3040	106,109
2006	31,245.28	25.00	4.00	1,187.32	18.14	0.2744	8,145
2007	94,963.98	25.00	4.00	3,608.63	18.88	0.2448	22,085
2008	1,092,659.33	25.00	4.00	41,521.05	19.64	0.2144	222,553
2009	220,746.92	25.00	4.00	8,388.38	20.41	0.1836	38,503
2010	4,360.73	25.00	4.00	165.71	21.18	0.1528	633
2011	1,126,533.19	25.00	4.00	42,808.26	21.97	0.1212	129,709
2012	399,874.13	25.00	4.00	15,195.22	22.77	0.0892	33,885
2013	2,241,130.03	25.00	4.00	85,162.94	23.57	0.0572	121,783
2014	728,362.48	25.00	4.00	27,677.77	24.38	0.0248	17,160
2015	279,747.25	25.00	4.00	10,630.40	24.90	0.0040	1,063
10,554,043.73				398,196.70	2,923,445		
15,454,389.28				462,342.21	3,944,140		

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.99

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 391.00 - OFFICE FURNITURE AND EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 15-SQUARE NET SALVAGE PERCENT.. +10							
2000	205,517.85	15.00	6.67	12,337.24	0.25	0.9833	181,883
2001	4,636.29	15.00	6.67	278.32	1.25	0.9167	3,825
2002	58,504.87	15.00	6.67	3,512.05	2.25	0.8500	44,756
2003	52,622.33	15.00	6.67	3,158.92	3.25	0.7833	37,099
2004	9,792.96	15.00	6.67	587.87	4.25	0.7167	6,316
2005	21,800.14	15.00	6.67	1,308.66	5.25	0.6500	12,753
2006	82,553.23	15.00	6.67	4,955.67	6.25	0.5833	43,340
2007	33,190.51	15.00	6.67	1,992.43	7.25	0.5167	15,434
2008	41,857.90	15.00	6.67	2,512.73	8.25	0.4500	16,952
2009	27,883.12	15.00	6.67	1,673.82	9.25	0.3833	9,620
2010	624.54	15.00	6.67	37.49	10.25	0.3167	178
2011	31,425.77	15.00	6.67	1,886.49	11.25	0.2500	7,071
2012	6,223.03	15.00	6.67	373.57	12.25	0.1833	1,027
2013	10,034.14	15.00	6.67	602.35	13.25	0.1167	1,054
2014	28,492.19	15.00	6.67	1,710.39	14.25	0.0500	1,282
2015	4,528.96	15.00	6.67	271.87	14.88	0.0080	33
	619,687.83			37,199.87			382,623
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.00							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 392.00 - TRANSPORTATION EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 7-S1							
NET SALVAGE PERCENT.. +5							
1980	7,413.23	7.00				1.0000	7,043
1981	29,736.14	7.00				1.0000	28,249
1984	16,990.00	7.00				1.0000	16,140
1985	147,140.00	7.00				1.0000	139,783
1988	3,450.00	7.00				1.0000	3,278
1990	11,900.00	7.00				1.0000	11,305
1995	16,500.00	7.00				1.0000	15,675
1996	30,898.00	7.00				1.0000	29,353
1998	112,001.16	7.00				1.0000	106,401
1999	156,637.90	7.00				1.0000	148,806
2001	198,565.15	7.00	14.29	26,956.21	0.07	0.9900	186,751
2002	71,644.99	7.00	14.29	9,726.17	0.34	0.9514	64,757
2003	70,472.83	7.00	14.29	9,567.04	0.62	0.9114	61,019
2004	166,279.14	7.00	14.29	22,573.22	0.92	0.8686	137,204
2005	145,100.20	7.00	14.29	19,698.08	1.23	0.8243	113,624
2006	113,612.10	7.00	14.29	15,423.41	1.58	0.7743	83,570
2007	366,024.40	7.00	14.29	49,689.64	1.95	0.7214	250,858
2008	531,503.03	7.00	14.29	72,154.19	2.35	0.6643	335,419
2009	365,565.28	7.00	14.29	49,627.31	2.81	0.5986	207,876
2010	188,376.93	7.00	14.29	25,573.11	3.32	0.5257	94,080
2011	155,354.30	7.00	14.29	21,090.12	3.90	0.4429	65,360
2012	39,420.35	7.00	14.29	5,351.51	4.58	0.3457	12,947
2013	16,211.10	7.00	14.29	2,200.74	5.36	0.2343	3,608
2014	99,511.10	7.00	14.29	13,509.13	6.26	0.1057	9,993
2015	128,300.40	7.00	14.29	17,417.42	6.88	0.0171	2,089
	3,188,607.73			360,557.30			2,135,188

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 11.31

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 393.00 - STORES EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 15-SQUARE							
NET SALVAGE PERCENT.. 0							
2000	9,660.29	15.00	6.67	644.34	0.25	0.9833	9,499
2003	16,601.94	15.00	6.67	1,107.35	3.25	0.7833	13,005
2004	4,345.53	15.00	6.67	289.85	4.25	0.7167	3,114
2008	8,691.48	15.00	6.67	579.72	8.25	0.4500	3,911
2009	36,769.22	15.00	6.67	2,452.51	9.25	0.3833	14,095
2013	56,682.76	15.00	6.67	3,780.74	13.25	0.1167	6,613
2014	42,598.41	15.00	6.67	2,841.31	14.25	0.0500	2,130
2015	15,476.85	15.00	6.67	1,032.31	14.88	0.0080	124
	190,826.48			12,728.13			52,491
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.67							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 394.00 - TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 15-SQUARE							
NET SALVAGE PERCENT.. 0							
2000	124,427.31	15.00	6.67	8,299.30	0.25	0.9833	122,353
2003	5,298.62	15.00	6.67	353.42	3.25	0.7833	4,151
2004	18,534.71	15.00	6.67	1,236.27	4.25	0.7167	13,283
2005	84,434.11	15.00	6.67	5,631.76	5.25	0.6500	54,882
2006	27,544.20	15.00	6.67	1,837.20	6.25	0.5833	16,067
2007	30,273.57	15.00	6.67	2,019.25	7.25	0.5167	15,641
2008	14,794.73	15.00	6.67	986.81	8.25	0.4500	6,658
2009	27,687.36	15.00	6.67	1,846.75	9.25	0.3833	10,613
2010	17,714.68	15.00	6.67	1,181.57	10.25	0.3167	5,610
2011	32,092.77	15.00	6.67	2,140.59	11.25	0.2500	8,023
2012	98,163.53	15.00	6.67	6,547.51	12.25	0.1833	17,996
2013	114,327.96	15.00	6.67	7,625.67	13.25	0.1167	13,339
2015	6,364.71	15.00	6.67	424.53	14.88	0.0080	51
	601,658.26			40,130.63			288,667
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.67							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 395.00 - LABORATORY EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 25-SQUARE							
NET SALVAGE PERCENT.. 0							
1990	176,817.81	25.00	4.00	7,072.71	0.25	0.9900	175,050
1992	23,454.00	25.00	4.00	938.16	2.25	0.9100	21,343
1993	28,309.40	25.00	4.00	1,132.38	3.25	0.8700	24,629
1996	56,498.44	25.00	4.00	2,259.94	6.25	0.7500	42,374
2006	15,487.26	25.00	4.00	619.49	16.25	0.3500	5,421
2007	20,258.70	25.00	4.00	810.35	17.25	0.3100	6,280
2010	9,930.51	25.00	4.00	397.22	20.25	0.1900	1,887
2013	32,587.58	25.00	4.00	1,303.50	23.25	0.0700	2,281
	363,343.70			14,533.75			279,265
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.00							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 396.00 - POWER OPERATED EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 27-S1.5							
NET SALVAGE PERCENT.. +15							
1974	58,737.58	27.00	3.70	1,847.30	3.41	0.8737	43,621
1975	45,325.23	27.00	3.70	1,425.48	3.67	0.8641	33,290
1976	3,978.78	27.00	3.70	125.13	3.94	0.8541	2,888
1978	25,000.00	27.00	3.70	786.25	4.50	0.8333	17,708
1981	7,949.78	27.00	3.70	250.02	5.39	0.8004	5,408
1984	2,577.10	27.00	3.70	81.05	6.37	0.7641	1,674
1989	172,607.46	27.00	3.70	5,428.50	8.26	0.6941	101,831
1991	70,050.00	27.00	3.70	2,203.07	9.14	0.6615	39,386
1997	314,355.22	27.00	3.70	9,886.47	12.26	0.5459	145,874
1999	327,659.74	27.00	3.70	10,304.90	13.50	0.5000	139,255
2000	295,714.31	27.00	3.70	9,300.22	14.16	0.4756	119,535
2001	470,785.39	27.00	3.70	14,806.20	14.85	0.4500	180,075
2002	9,856.53	27.00	3.70	309.99	15.57	0.4233	3,547
2003	43,298.03	27.00	3.70	1,361.72	16.32	0.3956	14,558
2004	361,693.96	27.00	3.70	11,375.28	17.10	0.3667	112,729
2005	28,918.05	27.00	3.70	909.47	17.91	0.3367	8,275
2006	39,807.10	27.00	3.70	1,251.93	18.74	0.3059	10,351
2007	82,866.61	27.00	3.70	2,606.15	19.61	0.2737	19,279
2008	664,303.53	27.00	3.70	20,892.35	20.50	0.2407	135,936
2009	820,681.41	27.00	3.70	25,810.43	21.41	0.2070	144,427
2010	562,678.44	27.00	3.70	17,696.24	22.35	0.1722	82,369
2011	88,326.15	27.00	3.70	2,777.86	23.30	0.1370	10,289
2012	16,420.50	27.00	3.70	516.42	24.27	0.1011	1,411
2013	354,353.64	27.00	3.70	11,144.42	25.26	0.0644	19,409
2014	5,544.45	27.00	3.70	174.37	26.25	0.0278	131
2015	36,914.16	27.00	3.70	1,160.95	26.88	0.0044	139
	4,910,403.15			154,432.17			1,393,395

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.14

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 397.00 - COMMUNICATION EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. IOWA 20-R3							
NET SALVAGE PERCENT.. +10							
1972	36,706.72	20.00				1.0000	33,036
1977	10,869.46	20.00				1.0000	9,783
1984	23,122.69	20.00	5.00	1,040.52	0.73	0.9635	20,051
1988	46,362.57	20.00	5.00	2,086.32	1.75	0.9125	38,075
1990	37,143.50	20.00	5.00	1,671.46	2.29	0.8855	29,602
1993	88,688.27	20.00	5.00	3,990.97	3.28	0.8360	66,729
1996	97,282.19	20.00	5.00	4,377.70	4.66	0.7670	67,154
1999	8,732.75	20.00	5.00	392.97	6.45	0.6775	5,325
2000	710,385.06	20.00	5.00	31,967.33	7.12	0.6440	411,739
2001	2,992.67	20.00	5.00	134.67	7.83	0.6085	1,639
2002	48,348.64	20.00	5.00	2,175.69	8.57	0.5715	24,868
2003	404,722.10	20.00	5.00	18,212.49	9.35	0.5325	193,963
2004	745,488.93	20.00	5.00	33,547.00	10.14	0.4930	330,773
2005	527,450.00	20.00	5.00	23,735.25	10.97	0.4515	214,329
2006	66,796.03	20.00	5.00	3,005.82	11.81	0.4095	24,618
2007	424,399.64	20.00	5.00	19,097.98	12.69	0.3655	139,606
2008	650,950.35	20.00	5.00	29,292.77	13.58	0.3210	188,060
2009	440,166.90	20.00	5.00	19,807.51	14.49	0.2755	109,139
2010	822,204.69	20.00	5.00	36,999.21	15.42	0.2290	169,456
2011	1,421,238.60	20.00	5.00	63,955.74	16.36	0.1820	232,799
2012	326,189.12	20.00	5.00	14,678.51	17.32	0.1340	39,338
2013	482,016.74	20.00	5.00	21,690.75	18.29	0.0855	37,091
2014	643,311.56	20.00	5.00	28,949.02	19.26	0.0370	21,422
2015	95,829.42	20.00	5.00	4,312.32	19.88	0.0060	517
	8,161,398.60			365,122.00			2,409,112

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.47

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 398.00 - MISCELLANEOUS EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 15-SQUARE							
NET SALVAGE PERCENT.. 0							
2000	299,698.66	15.00	6.67	19,989.90	0.25	0.9833	294,703
2007	28,290.15	15.00	6.67	1,886.95	7.25	0.5167	14,617
2008	300,745.88	15.00	6.67	20,059.75	8.25	0.4500	135,336
2013	2,642.73	15.00	6.67	176.27	13.25	0.1167	308
	631,377.42			42,112.87			444,964
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.67							

NORTHWEST TERRITORIES POWER CORPORATION

ACCOUNT 399.00 - OTHER TANGIBLE PROPERTY

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF MARCH 31, 2015

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL RATE (4)	ACCRUAL-- AMOUNT (5)	EXP. (6)	--ACCRUED FACTOR (7)	DEPREC.-- AMOUNT (8)
SURVIVOR CURVE.. 20-SQUARE							
NET SALVAGE PERCENT.. 0							
2000	21,051.12	20.00	5.00	1,052.56	5.25	0.7375	15,525
2002	1,042.41	20.00	5.00	52.12	7.25	0.6375	665
2008	101,921.91	20.00	5.00	5,096.10	13.25	0.3375	34,399
2011	108,420.60	20.00	5.00	5,421.03	16.25	0.1875	20,329
2012	257,770.56	20.00	5.00	12,888.53	17.25	0.1375	35,443
2013	133,855.20	20.00	5.00	6,692.76	18.25	0.0875	11,712
	624,061.80			31,203.10			118,073
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 5.00							

APPENDIX A

ESTIMATION OF SURIVOR CURVES

ESTIMATION OF SURVIVOR CURVES

Average Service Life

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

SURVIVOR CURVES

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the

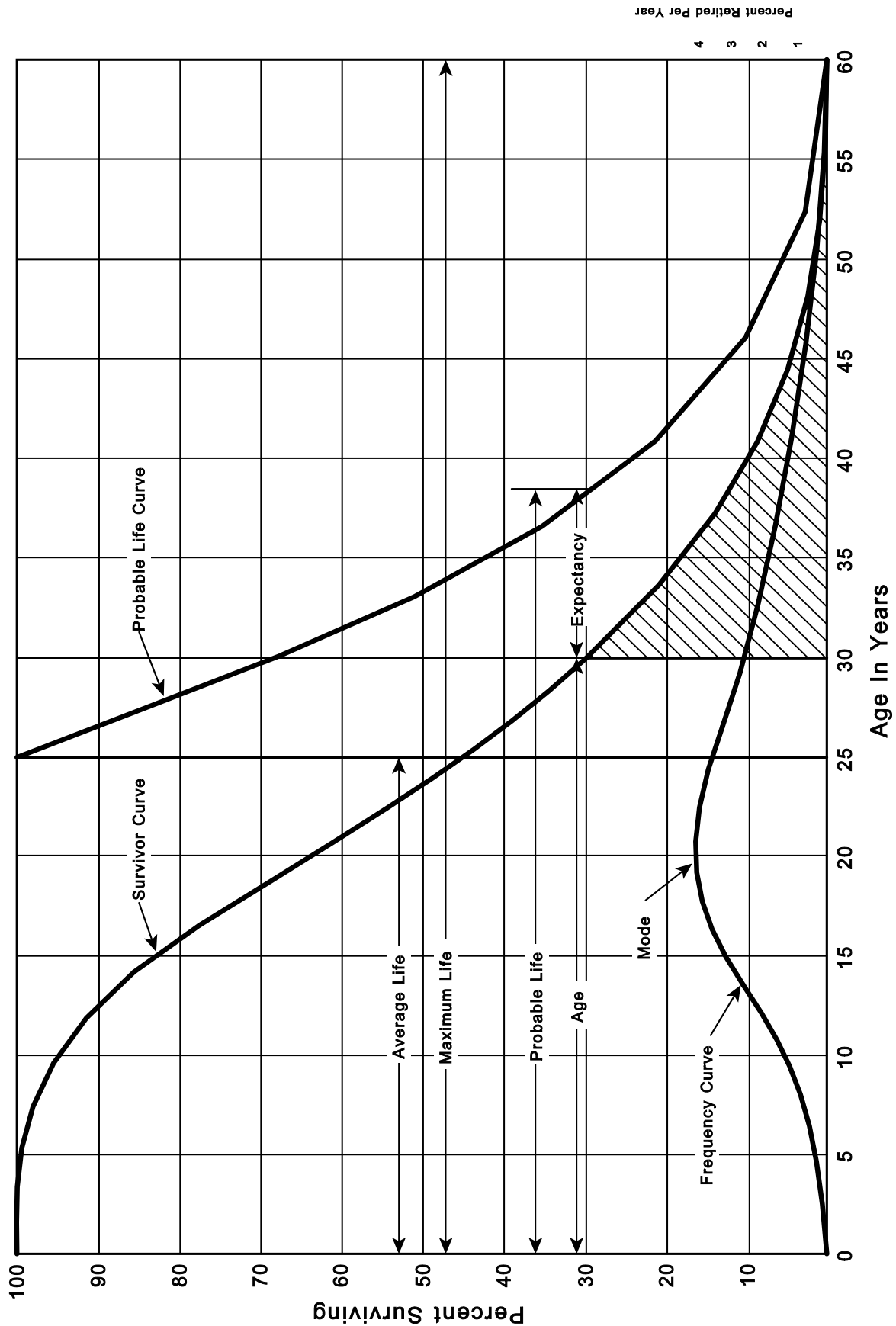


Figure 1. A Typical Survivor Curve and Derived Curves

Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.¹ These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."² In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis³ presenting his development of the fourth family consisting of the four O type survivor curves.

¹ Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

²Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

³Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

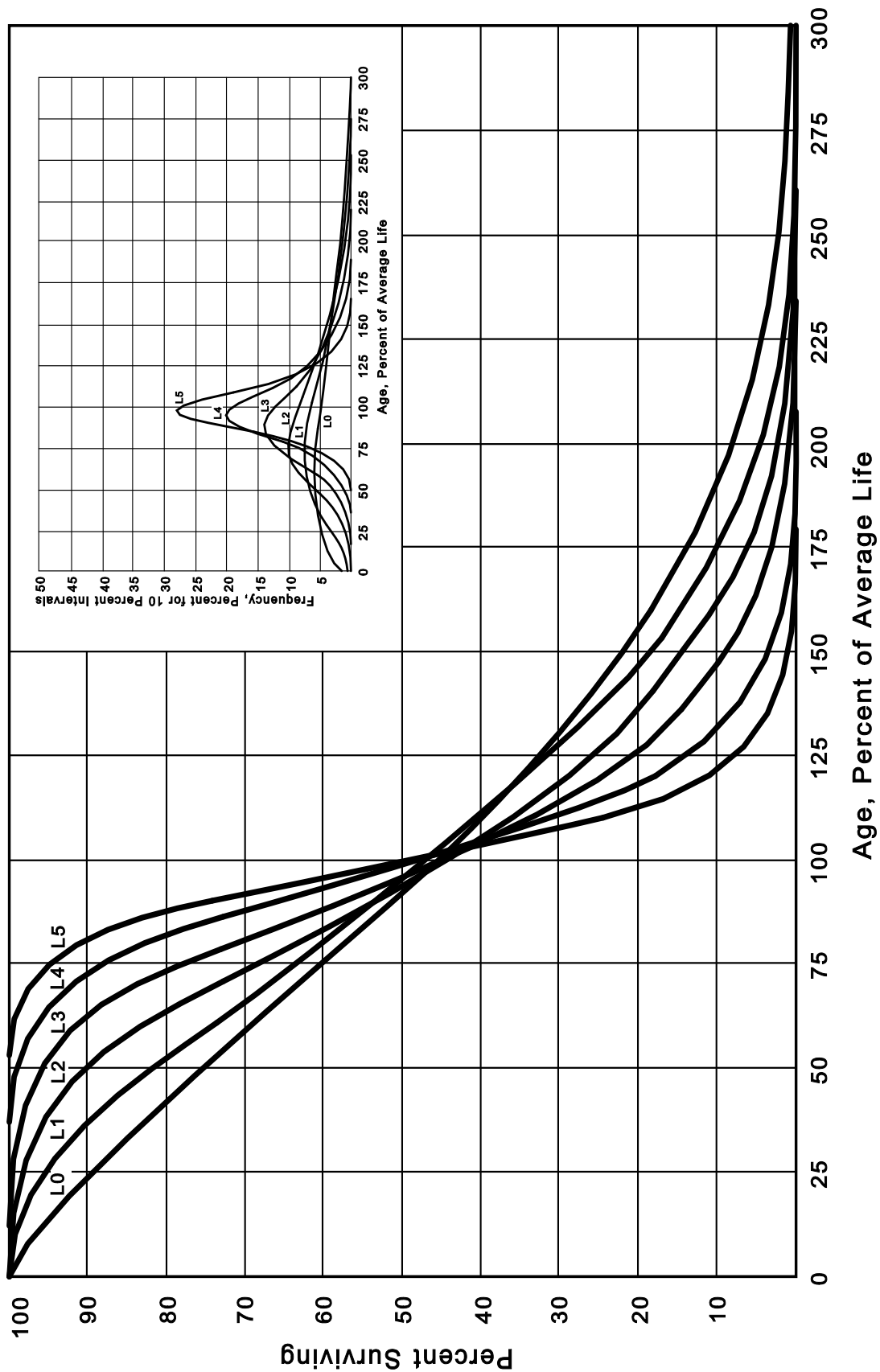


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

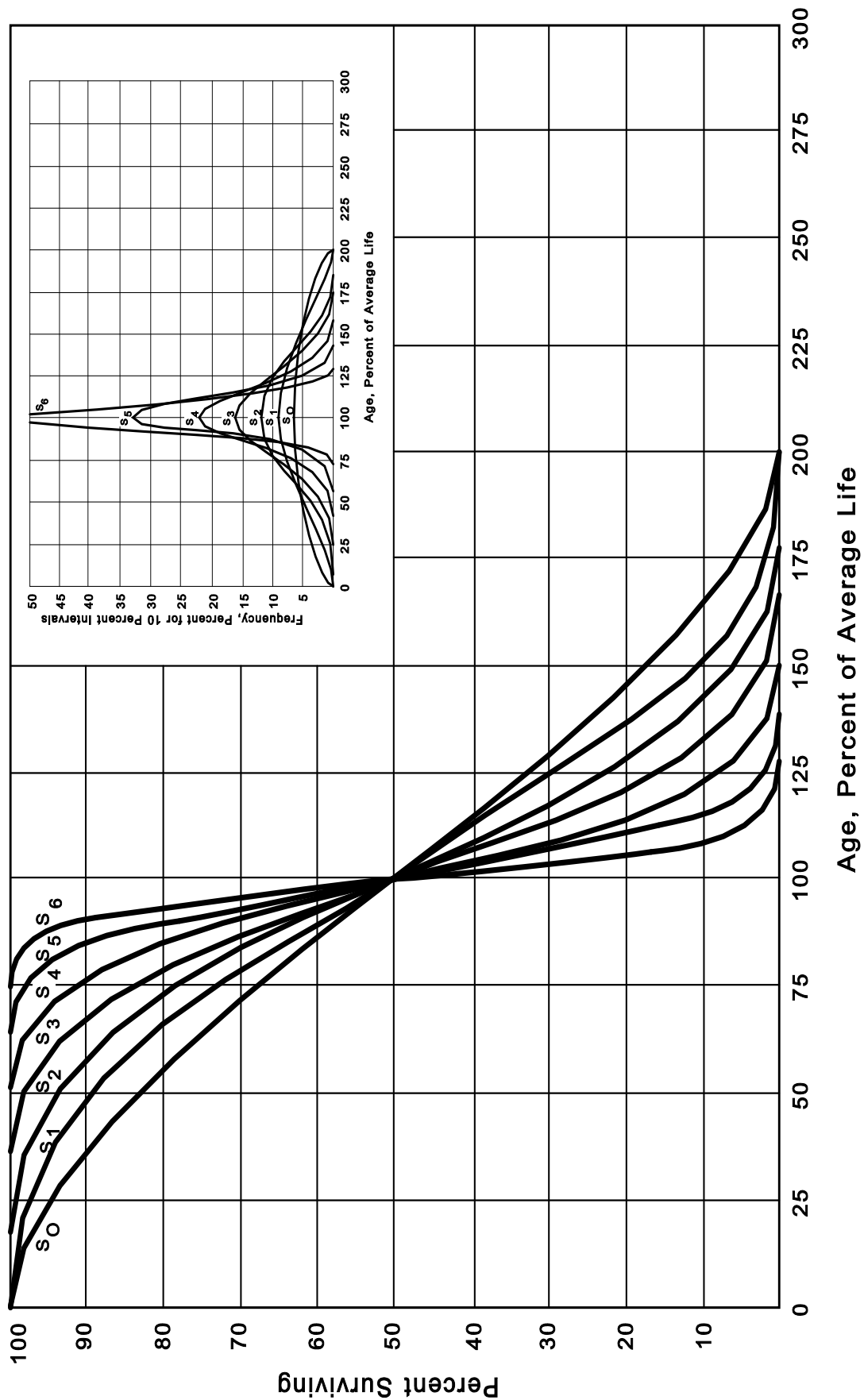


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

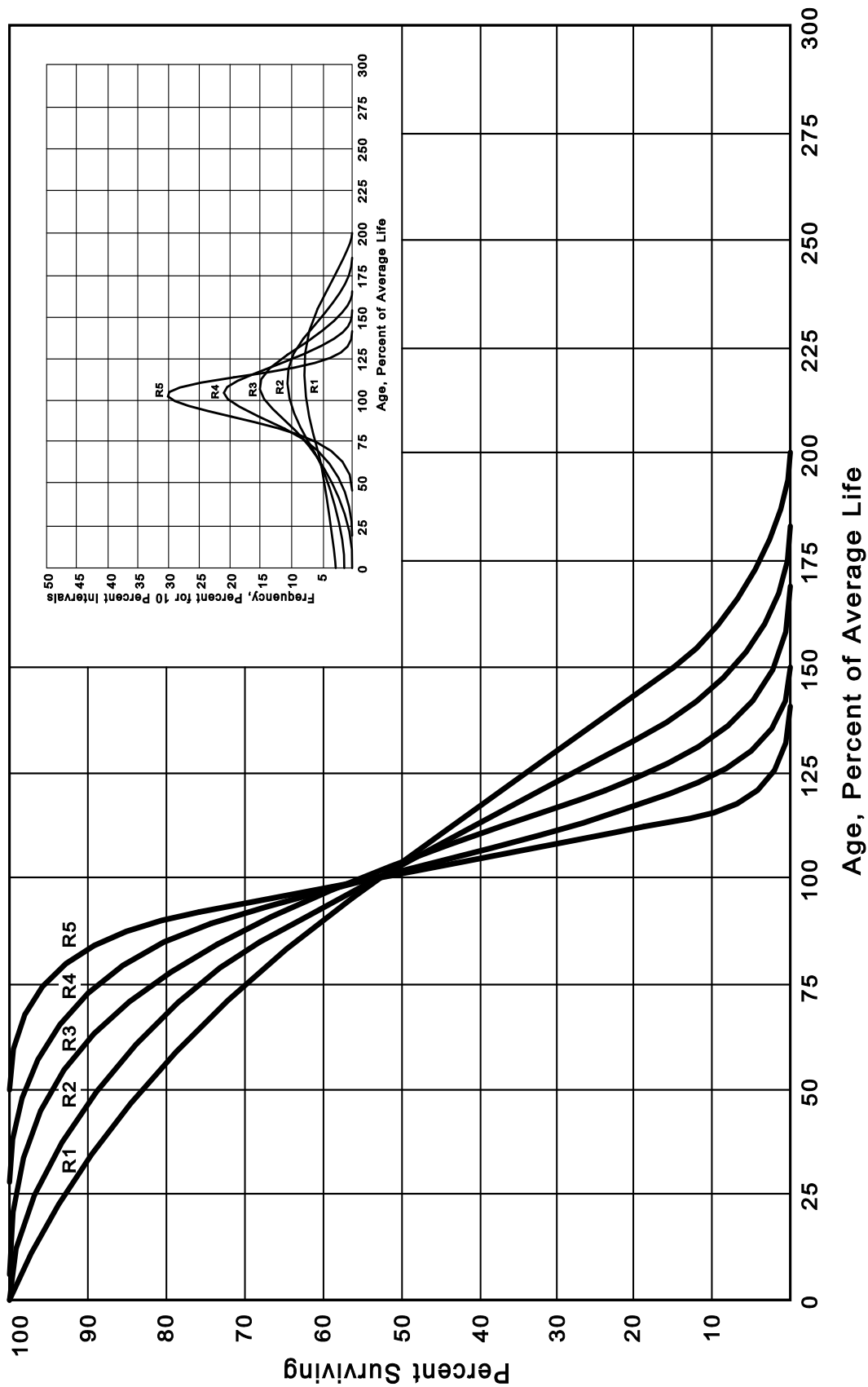


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

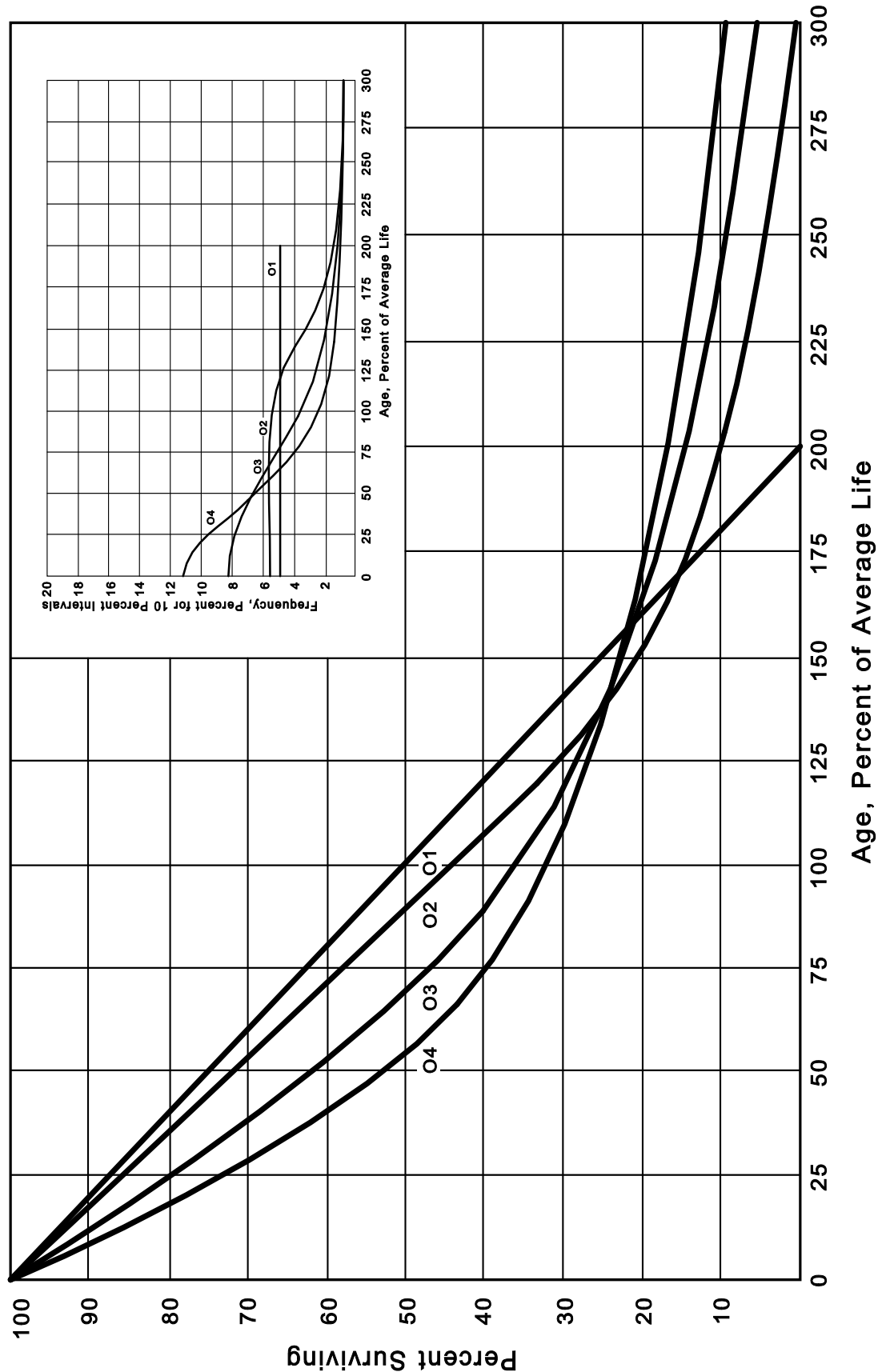


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"⁴ "Engineering Valuation and Depreciation,"⁵ and "Depreciation Systems."⁶

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2006-2015 during which there were placements during the years 2001-2015. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on the following pages. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, \$10,000 of the dollars invested in 2001 were

⁴Winfrey, Robley, Supra Note 1.

⁵Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.

⁶Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2006-2015
SUMMARIZED BY AGE INTERVAL

Year Placed	Retirements, Thousands of Dollars										Placement Band 2001-2015	
	During Year										Total During Age Interval	Age Interval
(1)	<u>2006</u> (2)	<u>2007</u> (3)	<u>2008</u> (4)	<u>2009</u> (5)	<u>2010</u> (6)	<u>2011</u> (7)	<u>2012</u> (8)	<u>2013</u> (9)	<u>2014</u> (10)	<u>2015</u> (11)	(12)	(13)
2001	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2002	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2003	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2004	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2005	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2006	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2007		5	11	12	13	14	15	16	18	20	113	7½-8½
2008			6	12	13	15	16	17	19	19	124	6½-7½
2009				6	13	15	16	17	19	19	131	5½-6½
2010					7	14	16	17	19	20	143	4½-5½
2011						8	18	20	22	23	146	3½-4½
2012							9	20	22	25	150	2½-3½
2013								11	23	25	151	1½-2½
2014									11	24	153	½-1½
2015										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2006-2015
SUMMARIZED BY AGE INTERVAL

Experience Band 2006-2015										Placement Band 2001-2015		
Acquisitions, Transfers and Sales, Thousands of Dollars												
Year Placed	During Year										Total During Age Interval	Age Interval
	2006 (1)	2007 (2)	2008 (3)	2009 (4)	2010 (5)	2011 (6)	2012 (7)	2013 (8)	2014 (9)	2015 (10)		
2001	-	-	-	-	-	-	-	60 ^a	-	-	-	13½-14½
2002	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2003	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2004	-	-	-	-	-	-	-	-	(5) ^b	-	60	10½-11½
2005	-	-	-	-	-	-	-	-	6 ^a	-	-	9½-10½
2006	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2007	-	-	-	-	-	-	-	-	-	-	-	7½-8½
2008	-	-	-	-	-	-	-	-	-	-	-	6½-7½
2009	-	-	-	-	-	-	-	-	(12) ^b	-	-	5½-6½
2010	-	-	-	-	-	-	-	-	22 ^a	-	-	4½-5½
2011	-	-	-	-	-	-	-	-	(19) ^b	-	10	3½-4½
2012	-	-	-	-	-	-	-	-	-	-	-	2½-3½
2013	-	-	-	-	-	-	-	-	-	(102) ^c	(121)	1½-2½
2014	-	-	-	-	-	-	-	-	-	-	-	½-1½
2015	-	-	-	-	-	-	-	-	-	-	-	0-½
Total	-	-	-	-	-	-	-	60	(30)	22	(102)	(50)

^a Transfer Affecting Exposures at Beginning of Year^b Transfer Affecting Exposures at End of Year^c Sale with Continued Use

Parentheses Denote Credit Amount.

retired in 2006. The \$10,000 retirement occurred during the age interval between $4\frac{1}{2}$ and $5\frac{1}{2}$ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of \$143,000 retired for age interval $4\frac{1}{2}$ - $5\frac{1}{2}$ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2006 retirements of 2001 installations and ending with the 2015 retirements of the 2010 installations. Thus, the total amount of 143 for age interval $4\frac{1}{2}$ - $5\frac{1}{2}$ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on the following page. The surviving plant at the beginning of each year from 2006 through 2015 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries

**SCHEDULE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2006-2015
SUMMARIZED BY AGE INTERVAL**

Experience Band 2006-2015											Placement Band 2001-2015	
Year Placed (1)	Exposures, Thousands of Dollars										Total at Beginning of Age Interval (12)	Age Interval (13)
	2006 (2)	2007 (3)	2008 (4)	2009 (5)	2010 (6)	2011 (7)	2012 (8)	2013 (9)	2014 (10)	2015 (11)		
2001	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2002	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2003	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2004	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2005	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2006	420 ^a	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2007		460 ^a	455	444	432	419	405	390	374	356	1,952	7½-8½
2008			510 ^a	504	492	479	464	448	431	412	2,463	6½-7½
2009				580 ^a	574	561	546	530	501	482	3,057	5½-6½
2010					660 ^a	653	639	623	628	609	3,789	4½-5½
2011						750 ^a	742	724	685	663	4,332	3½-4½
2012							850 ^a	841	821	799	4,955	2½-3½
2013								960 ^a	949	923	5,719	1½-2½
2014									1,080 ^a	1,069	6,579	½-1½
2015										1,220 ^a	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

^a Additions during the year.

shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2006 are calculated in the following manner:

Exposures at age 0	= amount of addition	= \$750,000
Exposures at age ½	= \$750,000 - \$ 8,000	= \$742,000
Exposures at age 1½	= \$742,000 - \$18,000	= \$724,000
Exposures at age 2½	= \$724,000 - \$20,000 - \$19,000	= \$685,000
Exposures at age 3½	= \$685,000 - \$22,000	= \$663,000

For the entire experience band 2006-2015, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$$255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.$$

Original Life Table

The original life table, illustrated in Schedule 4 on the following page, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent

SCHEDULE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2006-2015

Placement Band 2001-2015

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	<u>167</u>	<u>26</u>	0.1557	0.8443	42.24
					35.66

Total 44,780 1,606

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.

Column 3 from Schedule 1, Column 12, Retirements for Each Year.

Column 4 = Column 3 divided by Column 2.

Column 5 = 1.0000 minus Column 4.

Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15	
Exposures at age 4½	=	3,789,000	
Retirements from age 4½ to 5½	=	143,000	
Retirement Ratio	=	$143,000 \div 3,789,000$	= 0.0377
Survivor Ratio	=	$1.000 - 0.0377$	= 0.9623
Percent surviving at age 5½	=	$(88.15) \times (0.9623)$	= 84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an

average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

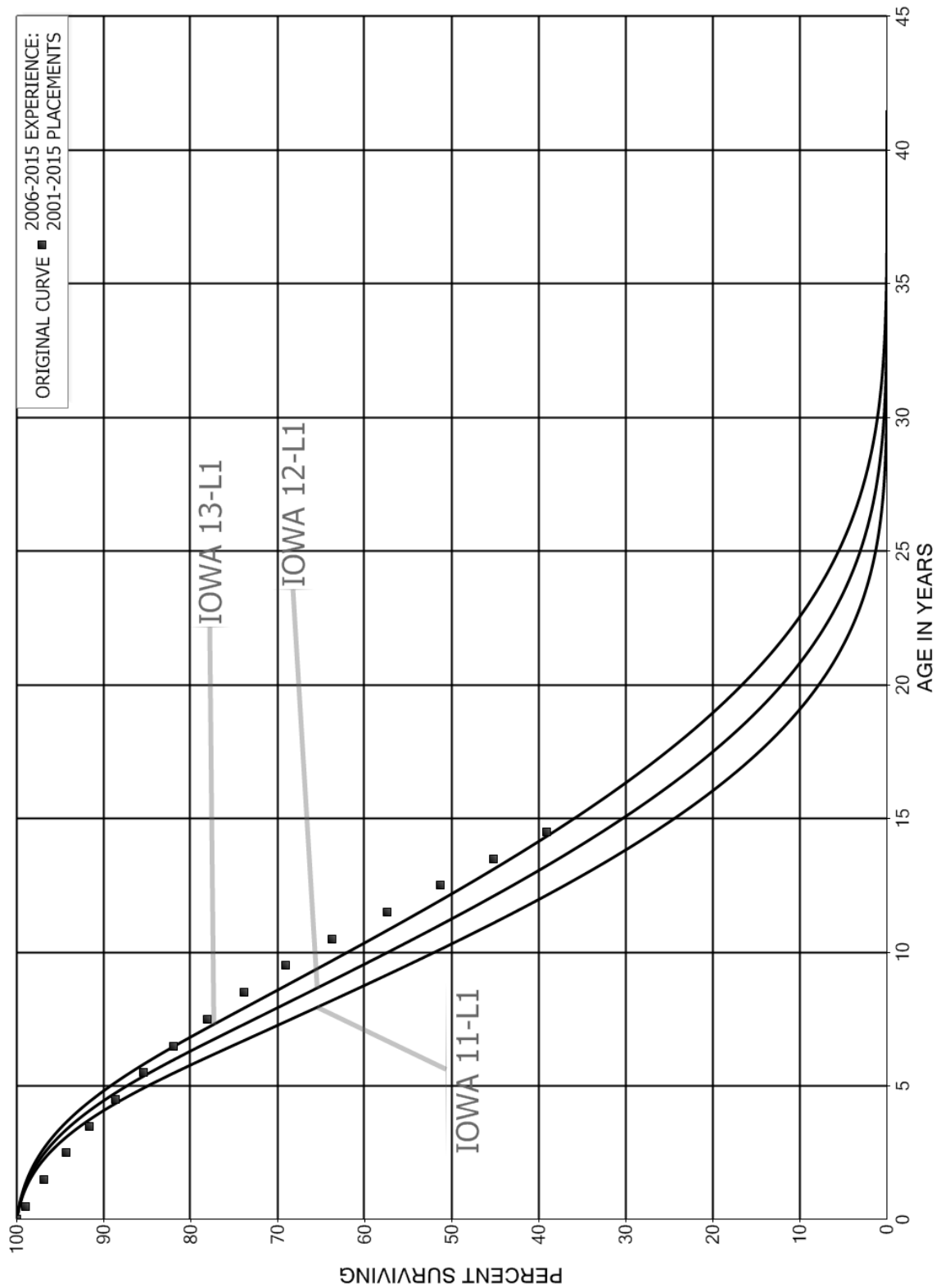


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

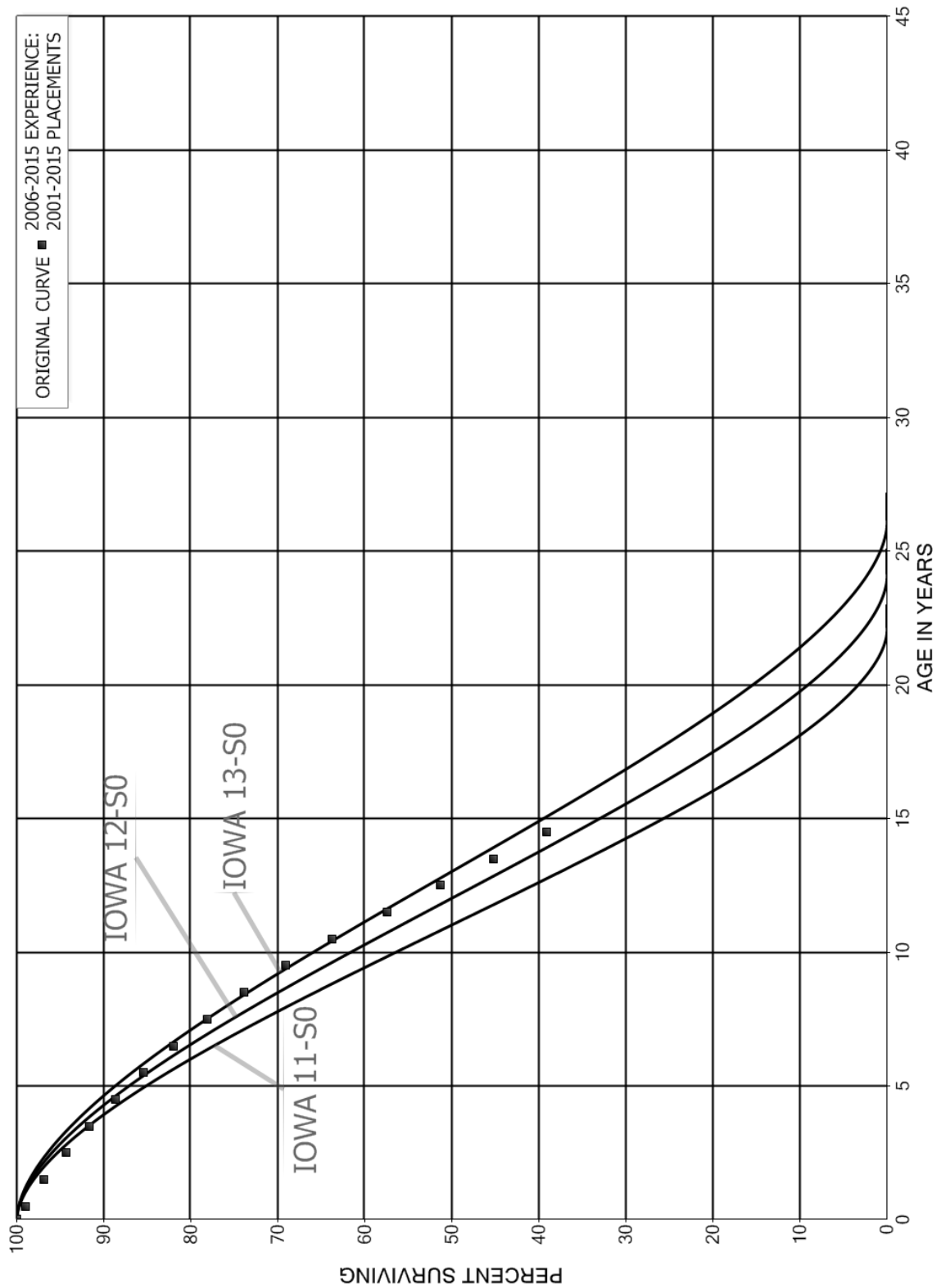


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

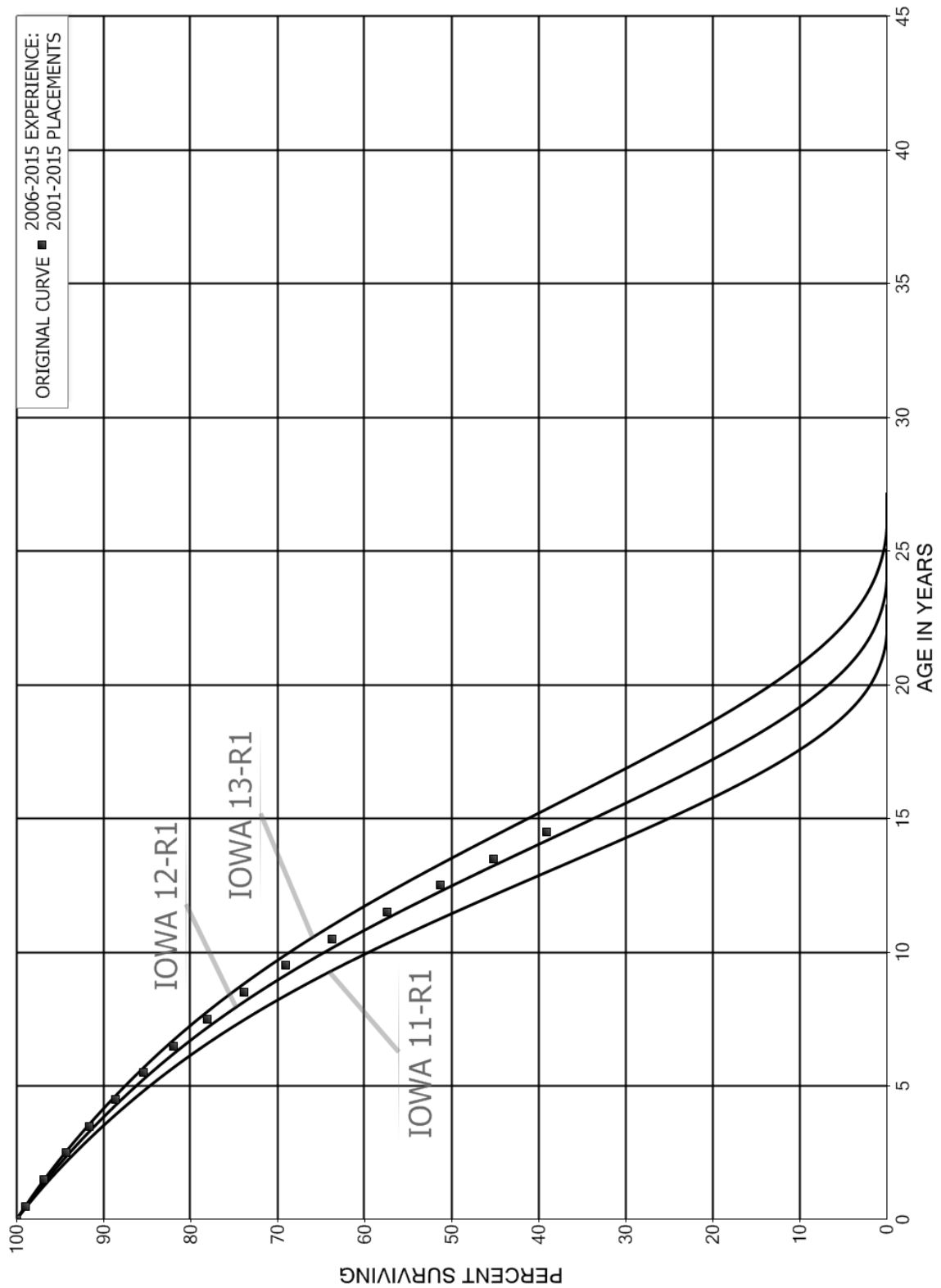
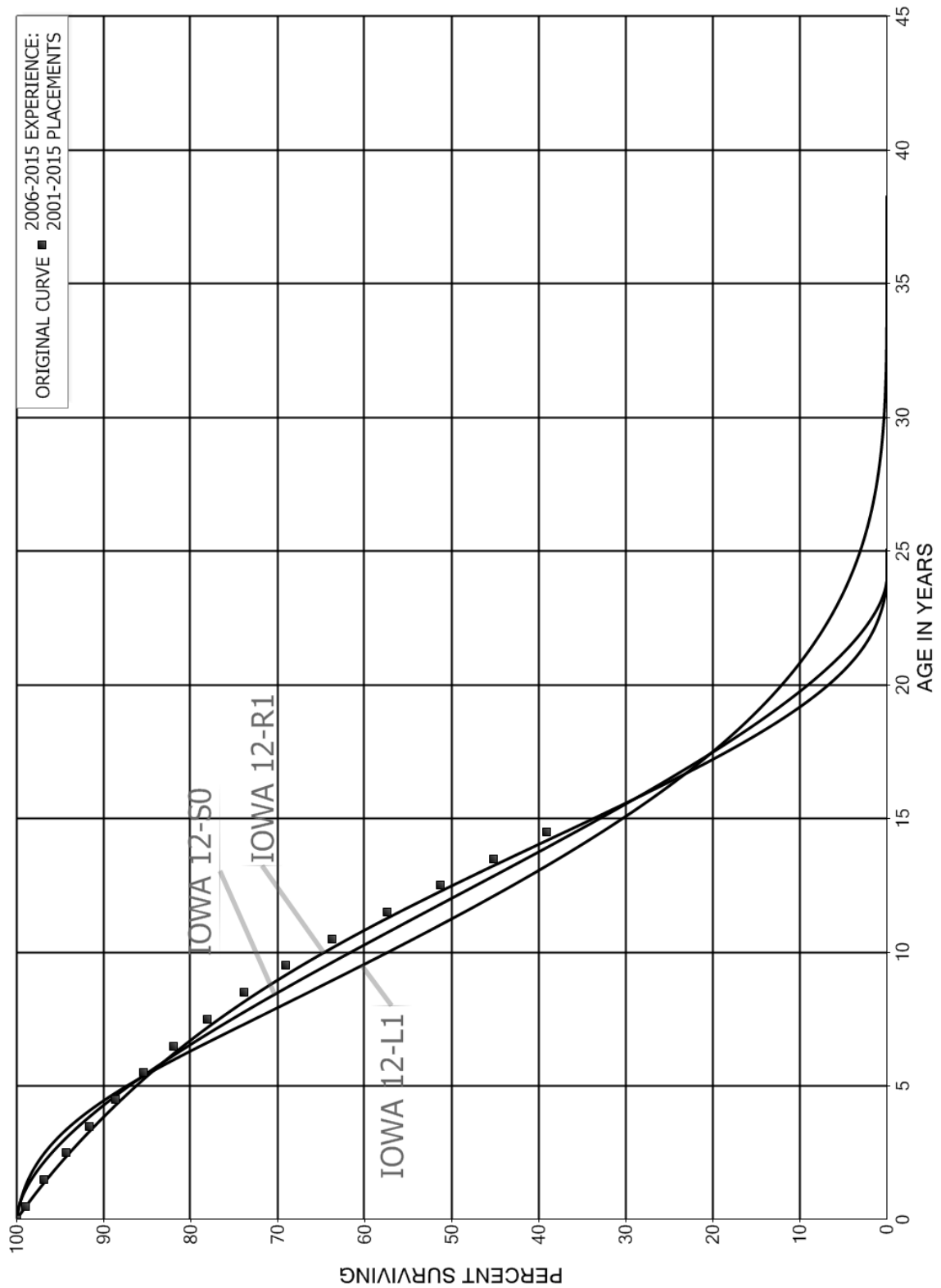


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



APPENDIX B

ESTIMATION OF NET SALVAGE

ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Gannett Fleming, in part on historical data, and in part through a comparison to peer companies. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements are used. Percentages of the cost of plant retired are calculated for each component of net salvage on both annual and three-year moving average bases.

The net salvage percentages estimated is usually determined using the “Traditional Approach” for net salvage estimation. When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceed (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account’s original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage percentage results.

The estimation of the net salvage percentages developed using the traditional approach, includes the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis are extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band.

4. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
5. Each account is then compared to the net salvage percentage currently approved, compared to peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Gannett Fleming, a net salvage percentage is determined for each account.
6. The net salvage percentage is then used in the depreciation rate calculations in the technical update.



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Appendix B

Business Cases

2014/15 Business Cases



NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to undertake a project to construct a fabric structure required for the storage of a new bucket truck for the Transmission and Distribution Division. NTPC will purchase a land lot in Fort Smith adjacent to the existing plant and clear the site in preparation for construction and allow site access. The present facilities at Fort Smith are not large enough for storage of the new bucket truck and a new facility must be constructed. The present lot does not have sufficient space for the construction of a new storage facility. If a new facility is not built, the Fort Smith plant will not have a location to store the new bucket truck.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option would require that the new bucket truck be stored outside. This would greatly reduce the service life of the truck, as well as reduce the capacity to react timely to emergencies/outages where the bucket truck is required during the winter months.

Option 2: Construct Stick Frame Structure

This option entails the purchase of the adjacent lot and construction of a stick frame structure for the storage of the bucket truck. The capital cost of this option is estimated at \$0.800M.

Option 3: Construct Insulated Fabric Structure

Option 3 involves the purchase of the adjacent lot and construction of an insulated fabric structure for the storage of the bucket truck. This is the least costly option estimated at \$0.623M. The benefits of this option are summarized as follows:

- The fabric structure meets the needs of the Corporation while minimizing capital costs.
- Storage of the new truck will reduce the truck's exposure to the elements while not in use and maximize the asset's useful life.
- Allows the Corporation to respond to emergency power outages.



Northwest Territories Power Corporation
Business Case
Bucket Truck Storage Facility

COST ESTIMATE

Table 1 – Budget Estimates

Project Budget

Description	2013/14	2014/15
Payroll Regular	15,000	-
Payroll OT	1,400	-
Payroll Fringe	4,200	-
Consultants Lump Sum	14,000	-
Contractors Lump Sum	295,000	115,000
Transportation	2,500	-
Accommodation	300	-
Meals	400	-
Permits/Licenses	200	-
Freight	6,000	-
Land & Rights	76,000	-
Total	\$415,000	\$115,000

Project Estimated Costs

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$412,000	\$1,500	\$70,000	\$483,500
2014/15	\$118,000	\$1,500	\$20,000	\$139,500
Total Project Cost				\$623,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 39 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.623M.
- Amortization rate of 2.54%.
- Return on Ratebase of 6.88%.
- Allocation costs to Taltson Zone only.



Northwest Territories Power Corporation
Business Case
Bucket Truck Storage Facility

Given the above assumptions, the average rate impact of the project for NTPC's Taltson Zone customers is estimated at 0.57%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$623	\$779	\$935	\$1,246
Amortization Period (Approx. Years)	39	39	39	39
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$16	\$20	\$24	\$32
Return on Ratebase (\$000)	\$43	\$54	\$64	\$86
Sub-Total: Revenue Requirement Increase (\$000)	\$59	\$73	\$88	\$117
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$59	\$73	\$88	\$117
Taltson Zone Revenue Requirement (\$000)	\$10,248	\$10,248	\$10,248	\$10,248
Average Percentage Rate Increase	0.57%	0.72%	0.86%	1.15%

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation purchased a new bucket truck and does not have enough space at its Fort Smith power plant to store the truck. As a result, NTPC is proposing to purchase a new land lot adjacent to the Fort Smith plant and construct an insulated fabric structure for truck storage, which will extend the usable life of the vehicle and allow timely emergency response during the winter period.

RECOMMENDATION

It is recommended that NTPC proceed with option 3. This option provides a solution that minimizes capital cost while providing the necessary accommodation for the new bucket truck. Total project costs to complete the project are estimated at \$0.623M.



Northwest Territories Power Corporation
Business Case
Bucket Truck Storage Facility

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections.</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks, which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

NTPC is proposing to undertake a project to correct deficiencies identified in a recent Dam Safety review of the Duncan Dam facility. This would involve replacing the timber decking on the Duncan Dam structure. The aging steel frame and wooden stop logs at the Duncan Dam spillway would also be replaced with a more modern and efficient lifting structure and aluminum stop logs.

These upgrades are required as the current infrastructure makes it difficult to add and remove stoplogs. There are a number of logs which cannot be removed. Stop logs are used to control the flow of water from Duncan Lake. The ability to place and remove stop logs is a critical function and Dam Safety requirement.

BACKGROUND

The Bluefish Hydro generating plant is located approximately 25 km north of Yellowknife and was constructed in 1942. This facility generates approximately 7 MW of electricity for the city of Yellowknife. The Duncan Lake Dam is the main water control structure located 17 km upstream of the Bluefish system, and was constructed in 1974. This dam is a concrete gravity structure with a stoplog spillway at its center, and overflow sections at either side. The Duncan Lake Dam is integral to the control and operation of the Bluefish system by providing storage of water from Duncan Lake. Duncan Dam is the primary water storage reservoir for the Bluefish hydro system.

At the present time, stoplogs at the spillway are lifted by a hand powered winch, and stored on the existing timber deck. The spillway can only be operated locally and the existing system presents many problems because of its age. Many times, the logs will shift during placement, causing jamming of the system. In addition, it is currently impossible to move the bottom log in the structure with the existing hoist. This prevents the Corporation from fully utilizing the reservoir capacity.

The timber decking at the facility is reaching a point where it will be unsafe for workers to use, which would prevent NTPC staff from adding or removing logs. Placing and removing stop logs at the spillway is a critical function, as the stop logs are used to control the flow of water from Duncan Lake. If the water cannot be controlled this would impact the ability to generate power from Bluefish plant and put the safety of the dam at risk.



ANALYSIS OF OPTIONS

Option 1: Do Nothing

While there is no immediate danger, the condition of the Duncan Dam spillway puts the safety of the dam at risk and the staff who operate the spillway. The spillway is a vital component of the dam and its safe and effective operation, making option one not viable.

Option 2: Upgrade Working Platform, Stoplogs and Lifting System Estimated Costs: \$537,000

This option would involve completing various upgrades at the Duncan Dam to correct the deficiencies in the recent Dam Safety Review. The following is a brief description of the upgrades:

- Replace existing wooden decking and rails with a new, steel structure with a larger working area. This decking will have a non-slip surface, and rails will be installed to a code compliant height.
- Replace wooden stoplogs with aluminum stoplogs. Replacing the wooden logs will allow personnel to more easily remove, and store the stop logs on the deck. The new stoplogs are significantly lighter than the wooden logs, and have a much tighter seal. This will allow for better water control on the Bluefish system.
- Replace existing winch system, with a new steel frame and central lift point system. This new system will allow for much easier and safer placement and removal of logs.

The benefits of option 2 are that it reduces risks in the following areas:

- Reliability – upgrades to the Duncan Dam spillway will enhance safety of the dam and enable it to continue to operate effectively
- Environmental – the spillway controls the release of water in flood situations. If staff cannot access the spillway due to safety concerns or cannot add and remove stops logs as needed, there is a risk of significant amounts of water being released in an uncontrolled way, with potentially significant negative environmental consequences.
- Financial – If staff cannot access the spillway due to safety concerns or cannot add and remove stops logs as needed, the dam could overtop results in damage or complete destruction of the dam. Such as replacement would involve a multi-million dollar capital investment.



Northwest Territories Power Corporation
Business Case
Duncan Dam Upgrade

COST ESTIMATE

Table 1 – Budget Estimates

Description	2013/14	2014/15	2015/16
Payroll	4,300	15,000	3,800
Payroll Overtime	500	4,000	-
Payroll Fringe Benefits	1,400	-	1,200
Consultants Lump Sum	1,800	58,500	15,000
Contractors Lump Sum	29,500	151,000	31,500
Transportation	1,200	85,000	10,000
Accommodation	-	1,500	-
Meals	-	1,000	-
Rental Equipment	-	6,000	-
Reservoirs/Dams/Waterways	-	5,000	-
Freight – other	-	11,000	-
Total Base Project Estimate	\$38,700	\$338,000	\$61,500

Project Cost Estimates

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2008/09 – 2013/14	\$38,700	\$2,904	\$6,394	\$47,998
2014/15	\$338,000	\$1,219	\$74,360	\$413,579
2015/16	\$61,500	-	\$13,500	\$75,000
Total				\$536,577



Northwest Territories Power Corporation
Business Case
Duncan Dam Upgrade

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 60 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.537M.
- Amortization rate of 1.67%.
- Return on Ratebase of 7.18%.
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.128%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$537	\$671	\$805	\$1,073
Amortization Period (Approx. Year)	60	60	60	60
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$9	\$11	\$13	\$18
Return on Ratebase (\$000)	\$39	\$48	\$58	\$77
Sub-Total: Revenue Requirement Increase (\$000)	\$47	\$59	\$71	\$95
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$47	\$59	\$71	\$95
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.128%	0.160%	0.192%	0.255%



Northwest Territories Power Corporation
Business Case
Duncan Dam Upgrade

SUMMARY OF BUSINESS CASE RATIONALE

A recent Dam Safety review of the Duncan Dam facility identified a number of deficiencies particularly with the spillway at the dam. To correct these deficiencies NTPC proposes the following. These include the replacement of the timber decking at the structure, installation of a new stop-log lifting structure and new aluminum stop logs at the spillway.

The spillway is a vital structure at the dam and allows for the control of water flows on the Bluefish system. If the problems at the spillway are not addressed the dam may cease operation. There is also a substantial environment risk. If the spillway does not function properly it would not allow a controlled release of water in a flood situation. This could mean that significant amounts of water may be released in an uncontrolled way, with potentially disastrous consequences.

There are also substantial financial risks to inaction. The dam could overtop resulting in damage or complete destruction of the dam. To replace the dam would involve a multi-million dollar capital investment.

RECOMMENDATION

It is recommended the Corporation proceed with the project as outlined in option 2. The total cost to complete the project is estimated at \$0.537M.



Northwest Territories Power Corporation
Business Case
Duncan Dam Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Engine Replacement Fort Good Hope

NEED FOR PROJECT

The Corporation is proposing to undertake a project to replace the G2 diesel generator at the Fort Good Hope power plant. In order to meet the Required Firm Capacity (RFC) requirements as required by the PUB, the G2 generator set (genset) will need to be replaced with a higher capacity unit. The RFC requirements dictate that if the largest engine was lost, the community peak would have to be met by 110% with the other two remaining engines. The CAT 3508 generator is the highest capacity unit in the plant rated at 480kW. If this unit was lost, the highest peak load would have to be met by the other CAT 3508 (480kW) and the CAT 353 (270kW) and there would be a shortfall in generation by 62kW or 8%. Therefore, based on the RFC requirements, the CAT 353 requires replacement. This genset was originally installed in 1982 when the power plant was newer and over the years the parts for this engine are becoming more difficult to procure. This unit is fuel inefficient with an efficiency of less than 3.4 kWh/L, and negatively impacts the overall power plant efficiency when it runs. This engine currently has 44,000 running hours, and is only used when necessary, accumulating minimal hours (392) over the 2009 to 2012 time period.

The plant fuel system requires enhancement, as the plants' day fuel tank is too low and the fuel system becomes air locked at times. The day tank needs to be raised higher to prevent air locks.

The existing plant heat recovery system is inadequate for G3 – CAT 3508. The hot side of the heat exchanger lacks the flow and temperature control to the power plant heating and the offline engines. As a result, the power plant and office are very cold in the winter when the G3 unit is online. In addition, when the G3 genset is the only unit online, the block heating to the offline engines is inadequate during the winter months and makes it difficult to start the engines, which increases the risk of power outages. The upgrade of the heat exchanger on G3 would allow the plant and engines to utilize the waste heat from this engine when the other engines are offline in the winter months.

BACKGROUND

The power plant in Kasho Go Tine (Fort Good Hope) was constructed in 1970 and currently has the following genset lineup: Two CAT 3508's rated at 480kW and one CAT D353 rated at 270kW. In 2012, an asset assessment was completed and concluded that the power demands of the community was reaching the maximum capacity of the plant.

The community experienced the following peaks during the 2012/13 winter season:

November - 738kW
December - 703kW
January - 707kW



Northwest Territories Power Corporation
Business Case
Engine Replacement Fort Good Hope

ANALYSIS OF OPTIONS

Option 1: Do Nothing

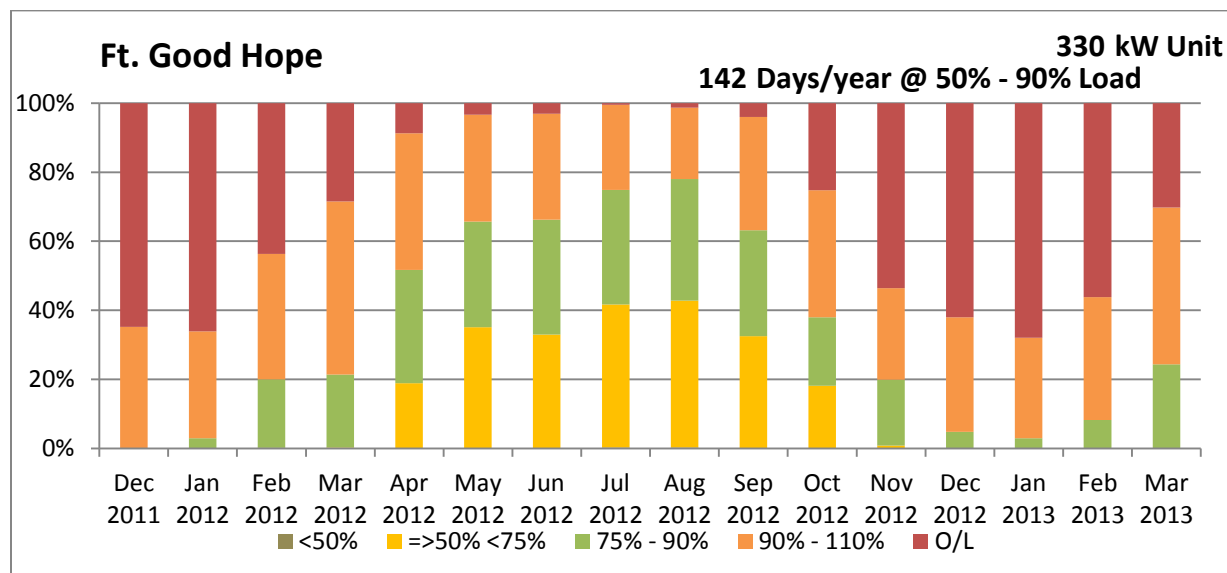
If the genset G2 – CAT D353 is not replaced, the power plant will not meet the RFC and the risk of extended outages will exist during the winter months. If the heat exchanger on G3 is not upgraded to provide the required flows for block heating during the winter months, the risk of engines not starting when needed due to the inefficient supply of engine block heating will remain. The risk will also remain for the gensets to run out of fuel if the day tank is not elevated to prevent air locks.

Option 2: Purchase New Diesel Generator Estimated Costs: \$950,000

This option requires the replacement of G2 – CAT D353 with a new electronic engine that is sized between 330 and 350kW to meet the power requirements of the community. The new electronic engine is also more fuel efficient than the existing engine. The heat exchanger and heating control upgrade on G3 will provide adequate heat and heating control to the engines that are offline reducing the risk of the engines not starting when required. The plant fuel system will be enhanced by raising the day tank to prevent air locks in the fuel supply to the engines. This will reduce the risk of the engines running out of fuel preventing power outages to the community.

The chart below is a graphic representation of a 330kW unit supplying the power requirements of the community based on the existing load requirements it would operate for 142 days at the optimum load range of 50% to 90% for maximum efficiency.

Table 1 – 330kW Engine Power Supply





Northwest Territories Power Corporation
Business Case
Engine Replacement Fort Good Hope

The bar graph above identifies the percentage the 330kW unit would be loaded based on historical load data for the community. The y-axis shows the percentage of time of that month it would be loaded and color identifies the percentage of load on the engine. The x-axis shows the month/year of known load data for the community applied to the 330kW unit. The overload (O/L) identifies that the load is too great for this unit to run on its own and another unit would have to be brought online to share the load, or a larger unit would have to be brought online to take the entire load for the community.

The Corporation will realize the following benefits from the implementation of option 2:

- RFC requirements will be met in Fort Good Hope.
- Overall plant efficiency is expected to improve with the acquisition of a more fuel efficient genset.
- The upgrade of the heat exchanger on the G3 generator would allow the plant and other gensets to utilize the waste heat from this engine, which will improve power plant heating and provide heating for the offline engines making them easier to start during the cold winter months.
- The fuel system enhancement will prevent air locks in the fuel supply and reduce the risk of running out of fuel thereby preventing power outages to the community.

Option 3: Purchase Used Genset Package

Estimated Costs: \$800,000

As with option 2, if a quality used genset package with very low engine hours and good fuel efficiency could be located and procured in a timely manner, this genset could be substituted with the new genset package providing a reduction in the genset package capital cost. As with option 2, the heat exchanger, and heating control on G3 would be upgraded. Also, the plant fuel system would be enhanced by raising the plant day tank to prevent air locks in the fuel supply.



Northwest Territories Power Corporation
Business Case
Engine Replacement Fort Good Hope

COST ESTIMATES

Table 2 – Budget Estimates

Description	2013/14	2014/15
Payroll Regular	20,000	102,500
Payroll Fringe	9,000	25,000
Contractors Lump Sum	70,000	200,000
Travel	3,000	10,000
Accommodations	1,500	5,000
Meals	1,500	5,000
Freight	10,000	17,500
Engines	105,000	90,000
Generator	70,000	-
Contingency	-	48,000
Total	\$290,000	\$503,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$290,000	\$10,000	\$50,000	\$350,000
2014/15	\$503,000	\$10,000	\$87,000	\$600,000
Total Cost				\$950,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.950M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.



Northwest Territories Power Corporation
Business Case
Engine Replacement Fort Good Hope

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.14%. The sensitivity analysis in Table 3 shows the rate impacts of various cost scenarios.

Table 3 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$950	\$1,188	\$1,425	\$1,900
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$38	\$48	\$58	\$77
Return on Ratebase (\$000)	\$46	\$58	\$69	\$93
Sub-Total: Revenue Requirement Increase (\$000)	\$85	\$106	\$127	\$169
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$85	\$106	\$127	\$169
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.14%	0.18%	0.22%	0.29%

SUMMARY OF BUSINESS CASE RATIONALE

The RFC requirements are not presently being met in the Town of Fort Food Hope. The purchase of a new higher capacity diesel genset will allow NTPC to ensure the community generation requirements are met and should increase the plants overall fuel efficiency, with the new genset operating in the most fuel efficient zone. The upgrading of the heat exchanger on G3 will allow for adequate heating of the engine block and power plant when G3 is online. Raising the plants day tank will prevent air locks in the fuel system reducing the risk of outages.

RECOMMENDATION

The Corporation recommends purchasing a new higher capacity diesel genset as outlined in option 2 unless a quality used generator (option 3) can be found in a timely manner.



Northwest Territories Power Corporation
Business Case
Engine Replacement Fort Good Hope

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

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Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 5.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Engine Replacement Jean Marie River

NEED FOR PROJECT / BACKGROUND

NTPC is proposing to undertake a project to replace a Detroit D4-71 diesel generator (G1) at the Jean Marie River power plant. This generator is an older unit that was manufactured in 1975 and its fuel efficiency is very poor averaging 2.67 kWh/L.

In addition, it is difficult to procure parts for this unit (genset) due to the age of the engine. The unit produces high levels of exhaust emissions and noise levels are extreme at 110 decibels (dB).

A water treatment plant is being planned for the Jean Marie River community. When this plant is operational it will add considerable load to the plant with a peak load of 38 kW. The addition of this new facility will create a deficit in plant capacity and additional generation capacity will be required.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option is not a viable option as the load in the community will increase significantly as a result of the new water treatment plant. Additional capacity is required.

Option 2: Purchase & Install New Genset Estimated Cost: \$540,000

This option requires the purchase and installation of new 106 kW air cooled Deutz generator to replace the existing Detroit D4-71 G1 generator.

The poor fuel efficiency of the G1 engine is negatively impacting the operations of the Jean Marie power plant. During 2010, this plant had a fuel efficiency of only 2.67 kWh/L. If plant efficiency is improved to 3.5 kWh/L, the Corporation would have saved nearly 25 thousand liters of diesel fuel annually. At a diesel cost of \$1.18/L (delivered), approximately \$30 thousand fuel savings could be achieved annually, with total savings of \$150 thousand over 5 years.

The benefits of this option are summarized below:

- Significantly improved diesel engine efficiency resulting in annual fuel savings of approximately \$30 thousand.
- Improved plant ventilation, reduced emissions and noise levels.
- Higher power plant generation capacity that meets the community load requirements, which improve overall plant reliability and eliminates potential capacity shortfalls.



Northwest Territories Power Corporation
Business Case
Engine Replacement Jean Marie River

COST ESTIMATES

Project Budget

Description	2012/13	2013/14
Payroll Regular	20,000	20,000
Payroll OT	1,000	10,000
Payroll Fringe Benefits	6,000	7,000
Contractors Lump Sum		56,000
Transportation	1,000	6,000
Accommodation		5,000
Meals	500	5,000
Mechanical Utilities		15,000
Diesel Engine	82,000	90,000
Generator	25,000	
Cooling System	22,000	
Exhaust System	3,500	
Power Cables	4,000	
Control Cables	3,000	
Freight	2,000	
Contingency	25,000	32,000
Total	195,000	246,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2012/13	\$195,000	\$12,000	\$33,000	\$240,000
2013/14	\$246,000	\$12,000	\$42,000	\$300,000
Total Project Cost				\$540,000



Northwest Territories Power Corporation
Business Case
Engine Replacement Jean Marie River

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates.

The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.540M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.031%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$540	\$675	\$810	\$1,080
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$22	\$27	\$33	\$44
Return on Ratebase (\$000)	\$26	\$33	\$39	\$53
Sub-Total: Revenue Requirement Increase (\$000)	\$48	\$60	\$72	\$96
Less: Estimated O&M Savings (\$000)	(\$30)	(\$30)	(\$30)	(\$30)
Total Revenue Requirement Impact (\$000)	\$18	\$30	\$42	\$66
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.031%	0.052%	0.072%	0.113%



Northwest Territories Power Corporation
Business Case
Engine Replacement Jean Marie River

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation is seeking to remedy the operational issues at the Jean Marie River power plant by replacing one of the aging diesel generation units. This will result in increased power output preventing outages due to shortfalls in installed capacity, and improved engine reliability and efficiency. The Corporation expects fuel annual savings of approximately \$30k annually. In addition, the plants ventilation will be improved and the noise level and exhaust emissions will be reduced.

RECOMMENDATION

It is recommended that NTPC proceed with the replacement of the G1 generator as outlined in option #2. The total costs to complete the project are estimated to be \$0.540M.



Northwest Territories Power Corporation
Business Case
Engine Replacement Jean Marie River

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page #3.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Gameti Engine Replacement & Plant Heat Recovery

NEED FOR PROJECT

The Corporation is proposing to undertake a project to replace the G2 CAT 3306 diesel generator and upgrade the heat exchanger on the G1 – CAT C10 generator (genset). The purpose of this project is to ensure the Gameti power plant is able to meet the power needs of customers.

In 2012, an asset assessment was completed of the Gameti power plant and concluded the power demands of the community were reaching the maximum capacity of the plant. Following the Required Firm Capacity (RFC) requirements, as laid out by the PUB, if the largest generator failed, the community peak would have to be met by 110% capacity of the other two remaining diesel generators. This would result in a generation shortfall of 55 kW or 13%. In order to meet this generation shortfall, the CAT 3306 would be replaced with a new genset. In addition, it is difficult to obtain replacement parts for the generator due to its age. The CAT 3306 genset was originally installed in 1975.

NTPC also proposes to replace the heat recovery system on G1 – CAT C10. The current heat exchanger lacks the flow and temperature control to provide residual heating to the plant facility and offline generators. As a result, when G1 is online the power plant and office trailer are too hot in the summer and too cold in the winter. The block heating to the offline engines is inadequate during the winter months making the engines difficult to start. As a result, a second engine must be run to provide adequate heat to the plant and gensets. In addition, the engines are equipped with electric block heaters consuming power of about 7.5 kW. Therefore, upgrading the heat exchanger on G1 would allow the removal of these block heaters.

BACKGROUND

The power plant in Gameti was constructed in 1975 and currently has the three diesel generators.

- G1 - CAT C10, rated at 210 kW
- G2 - CAT D3306, rated at 100 kW
- G3 - CAT 3412, rated at 300 kW

During the fall and winter season of 2012/13, the community experienced the following instantaneous and 15 minute peaks

October – Instantaneous 290 kW and 15 min peak 254 kW
November - Instantaneous 355 kW and 15 min peak 264 kW
December - Instantaneous 287 kW and 15 min peak 263 kW
January - Instantaneous 329 kW and 15 min peak 296 kW
February - Instantaneous 312 kW and 15 min peak 274kW

If the CAT 3412 – 300 kW unit went offline, the highest peak would have to be made up by the CAT C10 – 210 kW and the CAT 3306 – 100 kW, resulting in a generation shortfall of 55 kW.



Northwest Territories Power Corporation
Business Case
Gameti Engine Replacement & Plant Heat Recovery

Given the experience of the community in the winter of 2012/13, and based on the RFC as laid out by the PUB, additional capacity is required.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

Option 1 is not a viable option given the Gameti power plant is reaching its maximum capacity and risks extended power outages during the winter months. Failure to complete this project would continue to require the running of the G3 genset to provide block and plant heating and RFC may not be met.

Option 2: Replace D3306 with New Unit

Estimated Costs: \$1,100,000

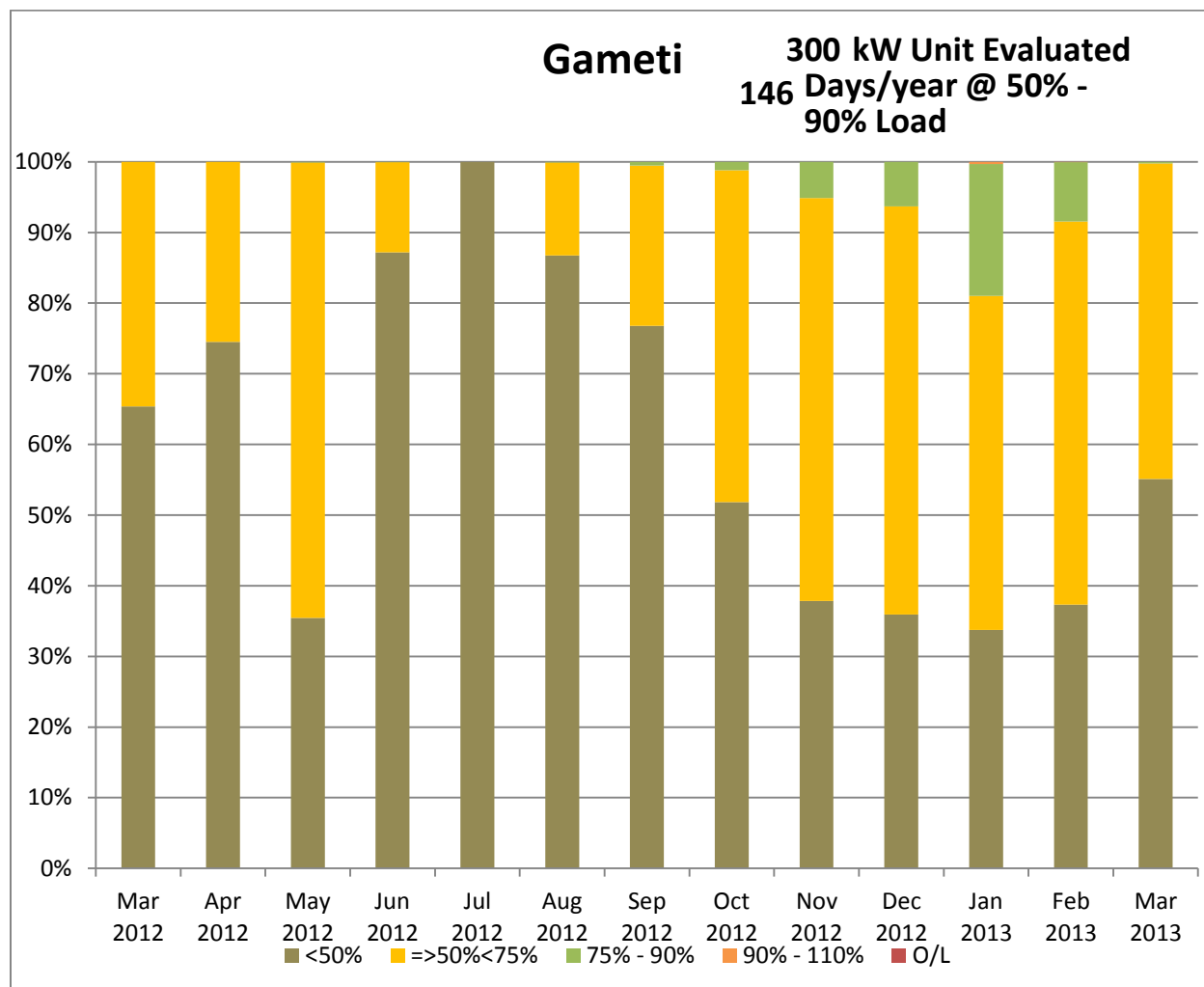
This option requires the replacement of the CAT D3306 with a new unit that has a generation capacity of 250 kW to 300 kW to meet the power requirements of the community. It also involves the upgrade of the heat exchanger on G1.

This option would also enable the Corporation to meet the capacity needs of the community and be compliant with PUB, RFC requirements.

The chart below shows that a properly sized unit in the 300 kW range will adequately supply the power requirements of the community running for 146 days at the optimum load range of 50% to 90% for maximum efficiency.



Northwest Territories Power Corporation
Business Case
Gameti Engine Replacement & Plant Heat Recovery



Option 3: Replace D3306 with Used Diesel Generator with Low Engine Hours
Estimated Costs: \$900,000

This option is similar to option 2, but instead of using a new unit, NTPC would use a high quality used unit with low engine hours. NTPC has been able to identify a suitable used diesel generator. As with Option 2 it also involves the upgrade of the heat exchanger on G1.

The benefits of this option are that it would also meet the capacity needs of the community, be compliant with PUB's, RFC requirements and lower the capital cost of the project.



Northwest Territories Power Corporation
Business Case
Gameti Engine Replacement & Plant Heat Recovery

COST ESTIMATES

Table 1 - Budget Estimates

Description	2013/14	2014/15
Payroll Regular	14,000	54,000
Payroll Fringe	4,000	18,000
Contractors Lump Sum	20,000	178,000
Transportation	1,500	3,500
Accommodation	1,500	3,500
Meals	500	4,000
Engine	182,000	-
Generator	45,000	-
Coolant System	-	50,000
Exhaust System	-	10,000
Heating Systems	-	40,000
Generator Switchgear / Cabling	-	8,000
Automation / Supervisory System	-	15,000
Freight	8,500	2,000
Contingency	2,000	49,000
Total Base Project Estimate	\$279,000	\$435,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$279,000	\$10,000	\$61,000	\$350,000
2014/15	\$435,000	\$20,000	\$95,000	\$550,000
Total Cost				\$900,000



Northwest Territories Power Corporation
Business Case
Gameti Engine Replacement & Plant Heat Recovery

RATE IMPACTS

The project will not have any impact on rates until the time of the next general rate application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.900M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.094%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$900	\$1,125	\$1,350	\$1,800
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$36	\$45	\$55	\$73
Return on Ratebase (\$000)	\$44	\$55	\$66	\$88
Sub-Total: Revenue Requirement Increase (\$000)	\$80	\$100	\$120	\$160
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$80	\$100	\$120	\$160
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.137%	0.172%	0.206%	0.275%



Northwest Territories Power Corporation
Business Case
Gameti Engine Replacement & Plant Heat Recovery

SUMMARY OF BUSINESS CASE RATIONALE

The power demands of the Gameti community are reaching the maximum capacity of the plant. NTPC must add additional capacity to the plant to provide reliable power service to the community of Gameti and be compliant with the RFC requirements of the PUB.

NTPC proposes the replacement of CAT 3306 diesel generator, as it is among the oldest at the facility, and replacing the heat recovery system on the G1 genset. These changes will provide enough capacity to meet the needs of the community, improve plant efficiency, and reduce the capital cost of the project.

RECOMMENDATION

It is recommended that the Corporation proceed with the proposed project as outlined in option 3 at an estimated capital cost of \$0.900M.



Northwest Territories Power Corporation
Business Case
Gameti Engine Replacement & Plant Heat Recovery

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 5.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

The Corporation is proposing to complete a project to address a number of deficiencies that negatively affect the reliability and safety at the Inuvik power plant. These deficiencies include:

- Plant systems that are a single point of failure for the plant.
- Critical systems lack redundancy.
- Systems do not allow for manual operation by site staff.
- Lack of equipment protection systems.

BACKGROUND

The Inuvik power plant consists of two separate buildings namely the K-Plant built in 1970 and the EMD Plant rebuilt in 1984 after a fire. The K-Plant houses two natural gas fuelled units and one diesel unit. The EMD plant has four diesel generating units, two 2,500 KW EMD units, a 760 kW CAT D399 unit and a 300 kW Cummins unit. Total installed capacity is 13,720 kW.

Since the K-Plant was converted to natural gas in the late 1990's, the EMD plant in Inuvik has been considered to be a standby plant. Consequently, it has received a level of capital expenditures in line with its primary function as a backup plant. In January and February 2012 two outages occurred at the plant. After completing an investigation, the Corporation has determined that there are a number of deficiencies at the plant that negatively affect its reliability, operation and safety. These include the following:

- At present time, there is no local mode available to allow plant operators to run generators manually.
- The radiator control (which cools all the diesel engines) is within the station PLC (programmable logic controller). If the PLC fails the radiator control is lost. This is a single point of failure and must be rectified.
- Operators do not receive timely warnings of temperature increases occurring on an engine
- Current circuit breakers on generators do not always trip (interrupt power flow after detecting a fault) this has resulted in damage to units.
- The deadbus relays are not paralleled and if one fails the power feeds will automatically trip (fault/fail) thereby representing a single point of failure.
- The current residual heating system controller at the plant is out of date
- The current residual heating system failsafe is not adequate and requires replacement with a new 3-way valve.
- The computers in the Inuvik plant are outdated and past their useful life.



ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option does not address the reliability of the plant, or safety at the plant. The costs of inaction would include additional hours from the engineering department to support plant operations and continued risks to plant equipment and possible staff. Over time these costs could prove to be substantial and far in excess of the cost of resolving the problems at the plant.

Option 2: Inuvik Plant Reliability Upgrade Estimated Costs: \$608,000

This option involves correcting the operational plant deficiencies and updating critical systems to prevent future plant failure and allow manual operation on site. The following upgrades/repairs would be completed:

- The addition of Local, Remote and Maintenance modes for all gensets, allowing for manual operation if required
- Relocation of the radiator control unit. This requires the installation of various temp sensors and relocation of the radiator control unit to the engine PLC.
- Installation of a G7 jacket water sensor. This will allow engine temperature alarms to be generated by an analog signal, and will provide a timelier alert to the plant operator along with improved early detection of problems.
- Installation of new breaker fail safe on gensets. This would include an Engine Run Relay, PLC fail relay and power supply fail relay.
- Replace deadbus relays in the plant to prevent unnecessary system faults
- Install new residual heating system controller in the plant
- Installation of a new failsafe 3-way valve on the plant residual heating system.
- Upgrade the computer equipment at the Inuvik power plant.

By correcting the deficiencies and updating the critical system as noted above, the following benefits would be realized:

- Improved reliability and operability of the plant with less downtime and system failures.
- Increased protection of the plant thereby increasing the onsite safety for personnel.
- Plant upgrades will avoid costs associated with potential failures from operating the plant in its present condition over the long-term.



Northwest Territories Power Corporation
Business Case
Inuvik Plant Reliability Improvement

COST ESTIMATES

Table 1 – Budget Estimates

Description	2012/13	2013/14	2014/15
Payroll Regular	10,000	42,500	19,000
Payroll OT	-	10,000	4,500
Payroll Fringe	3,000	15,000	7,000
Consultants Lump Sum	-	10,000	-
Contractor	12,500	61,000	187,000
Transportation	1,500	-	-
Accommodations	1,000	-	-
Meals	-	500	-
Construction Camp	-	500	-
Freight	500	2,000	7,000
Customer Metering		5,500	-
Automation/Supervisory System	5,000	80,000	12,000
Micro-Computers Hardware	-	4,000	-
Total	\$33,500	\$231,000	\$236,500

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2012/13	\$33,500	\$1,000	\$5,500	\$40,000
2013/14	\$231,000	\$10,000	\$39,500	\$280,500
2014/15	\$236,500	\$10,000	\$41,000	\$287,500
Total Project Cost				\$608,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.608M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.



Northwest Territories Power Corporation
Business Case
Inuvik Plant Reliability Improvement

- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.09%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$608	\$760	\$912	\$1,216
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$25	\$31	\$37	\$49
Return on Ratebase (\$000)	\$30	\$37	\$44	\$59
Sub-Total: Revenue Requirement Increase (\$000)	\$54	\$68	\$81	\$108
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$54	\$68	\$81	\$108
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.09%	0.12%	0.14%	0.19%

SUMMARY OF BUSINESS CASE RATIONALE

In 2012, two outages occurred at the Inuvik EMD plant that prompted the Corporation to complete an investigation. It was determined that there were a number of deficiencies at the plant that negatively affected its reliability, operation and equipment safety of the facility. The Corporation has identified the causes of these deficiencies and identified solutions to resolve them. The completion of the reliability improvement at the Inuvik EMD plant will enable the Corporation to improve its reliability and enhance the safety of the equipment and staff at the plant. Selecting this option will also avoid the costs associated with potential failures from operating the plant in its present condition over the long-term. The project will provide plant operators with more control and reduce the reliance on the Engineering Division in Hay River if an equipment failure occurs

RECOMMENDATION

It is recommended the Corporation proceed with the general cleanup at the Inuvik EMD as outlined in option 2. The total costs to complete the project are estimated to be \$0.608M.



Northwest Territories Power Corporation
Business Case
Inuvik Plant Reliability Improvement

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Inuvik – Road Widening Behind Warehouse

NEED FOR PROJECT

NTPC is proposing to undertake a project to widen a narrow road located behind the Company's warehouse in Inuvik. The road behind the warehouse is extremely narrow making it difficult to deliver supplies to the warehouse, and creates a safety hazard for personnel. However, the road cannot be widened without the construction of a retaining wall system, due to the grade (angle) from the road to adjacent lots owned by other parties. The project will require installation of approximately 60 meters of retaining wall and the subsequent widening of the road to address the access and safety issues.

BACKGROUND

The warehouse in Inuvik was constructed in 2012 to hold chemical liquids (lube and glycol as well as capital project and maintenance materials for power generation systems. The warehouse is the main distribution site for all materials required by the Beaufort/Delta communities. As a result, the road leading to the warehouse must accommodate large transportation vehicles that pick up inventory and make daily deliveries. The road is heavily travelled with 5 ton-trucks, large vans, and half-ton trucks completing over 40 pick-ups/deliveries per week. The road leading to the warehouse has been in use since 1975 when the K-plant was built. It is the only road that provides access to the Corporation's warehouse.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option does not address the current access and safety issues with respect to the existing road.

Option 2: Road Widening behind Inuvik Warehouse Estimated Costs: \$546,000

This option involves the installation of a pre-engineered retaining wall along the access road and the subsequent widening of the road. This approach will permit the widening of the road surface without encroachment on adjacent properties. As part of the road widening construction process, new gravel will be installed. The benefits of this option are summarized as follows:

- Improved safety for personnel with the new road providing reliable and safe access to the warehouse.
- Use of high quality materials (new gravel) will increase durability of the road, extend its useful life and reduce road maintenance expenses over the long term.
- Improved efficiency with respect to supply delivery and logistical operations.



Northwest Territories Power Corporation
Business Case
Inuvik – Road Widening Behind Warehouse

COST ESTIMATES

Table 1 – Budget Estimates

Description	2013/14	2014/15	Total
Payroll Regular	2,000	6,000	8,000
Payroll OT	-	4,000	4,000
Payroll Fringe	1,000	2,000	3,000
Consultants Lump Sum	12,000	-	12,000
Contractors Lump Sum	71,000	330,000	401,000
Freight	17,000	-	17,000
Total	103,000	342,000	445,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$103,000	\$4,000	\$18,000	\$125,000
2014/15	\$342,000	\$3,000	\$76,000	\$421,000
Total				\$546,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.546M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.08%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
Inuvik – Road Widening Behind Warehouse

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$546	\$683	\$819	\$1,092
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$22	\$28	\$33	\$44
Return on Ratebase (\$000)	\$27	\$33	\$40	\$53
Sub-Total: Revenue Requirement Increase (\$000)	\$49	\$61	\$73	\$97
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$49	\$61	\$73	\$97
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.08%	0.10%	0.12%	0.17%

SUMMARY OF BUSINESS CASE RATIONALE

The road behind the warehouse in Inuvik is too narrow and is causing safety concerns. To address these concerns, the Corporation is proposing to widen the road at the Inuvik warehouse. In order to complete this project, NTPC will have to construct a new retaining wall to protect adjacent properties.

Completing this road widening project will provide safer and more reliable access to the warehouse. The Inuvik warehouse is the main distribution site for all materials required by the Beaufort/Delta communities. It's safe and reliable operation is critical to NTPC's operations.

RECOMMENDATION

The Corporation recommends the construction of a new retaining wall and the widening of the road at the Inuvik warehouse as outlined under option 2. This will enable safe and reliable access to the warehouse. The total costs to complete the project are estimated to be \$0.546M.



Northwest Territories Power Corporation
Business Case
Inuvik – Road Widening Behind Warehouse

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
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Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
3 Phase, Automation & Breaker Upgrade

NEED FOR PROJECT

NTPC is proposing to undertake a project to complete the second phase of automating the Jean Marie River diesel plant. The new breaker contactors and generator protection relays were recently installed for the three gensets. The next step for implementing the plant automation is to install two new feeder switchgear cabinets, breaker contactors, feeder protection and upgrading the single phase distribution with three phase distribution.

BACKGROUND

Jean Marie River diesel plant has three single phase generators and was constructed in 1973. During the 2012 plant condition assessments, it was identified that the three gensets that supply power to the community have breaker contactors that do not have the functionality to be automated. In addition, the feeder breakers are molded case breakers that also cannot be automated and must be operated manually to open and close.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The old feeder breakers have reached the end of their life and require replacement. If they are not replaced, they could fail resulting in difficulty restoring power to the community after an outage. Not upgrading the community from single phase to three phase decreases the reliability of the plant to produce the power requirements at peak loads.

Option 2: Installing Feeder Breaker Contractors, Relays, and Feeder Protection

This option consists of installing new feeder breaker contactors, relays and feeder protection. The new breaker contactors will extend the power plant's life and is the next step in automating the plant. The capital cost of this option is estimated at \$0.961 million. The benefits of option 2 are summarized as follows:

- The upgrading from single phase to three phase distribution will increase the plant's reliability for power requirements during peak loads.
- Improved operational performance from automated system.
- Decreased time required to restore power after a power outage occurs.



Northwest Territories Power Corporation
Business Case
3 Phase, Automation & Breaker Upgrade

COST ESTIMATES

Table 1 – Budget Estimates

Description	2013/14	2014/15
Payroll Regular	\$30,000	\$25,000
Payroll OT	\$8,600	\$9,000
Payroll Casual	\$900	\$400
Payroll Casual OT	\$500	\$0
Payroll Fringe	\$10,000	\$7,000
Consultants Lump Sum	\$22,000	\$1,000
Contractors Lump Sum	\$466,000	\$0
Transportation	\$16,000	\$1,500
Accommodation	\$1,300	\$2,500
Meals	\$1,400	\$1,500
Equipment Rental	\$6,000	\$2,800
Construction Camps	\$0	\$1,400
Freight	\$14,000	\$2,000
Site Electrical (Breakers & Relays)	\$130,000	\$15,000
Transfer Project Costs	\$2,200	\$0
Total	\$708,900	\$69,100

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$708,900	\$24,836	\$130,503	\$864,238
2014/15	\$69,100	\$25,299	\$2,101	\$96,500
Total Project Cost Estimate				\$960,739



Northwest Territories Power Corporation
Business Case
3 Phase, Automation & Breaker Upgrade

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.961M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.15%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$961	\$1,201	\$1,441	\$1,921
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$39	\$49	\$58	\$78
Return on Ratebase (\$000)	\$47	\$58	\$70	\$94
Sub-Total: Revenue Requirement Increase (\$000)	\$86	\$107	\$128	\$171
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$86	\$107	\$128	\$171
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.15%	0.18%	0.22%	0.29%



Northwest Territories Power Corporation
Business Case
3 Phase, Automation & Breaker Upgrade

SUMMARY OF BUSINESS CASE RATIONALE

This project includes the installation of new feeder breaker contactors, relays and feeder protection. These installations are the next step to fully automating the plant. The new additions will also extend the power plant's useful life as well as its reliability during peak loads. The plant's increased reliability comes from switching from one phase to a three phase distribution. This upgrade will allow for increased reliability during peak load periods.

RECOMMENDATION

It is recommended the Corporation proceed with the project as outlined in option 2. The total cost to complete the project is estimated at \$0.961M.



Northwest Territories Power Corporation
Business Case
3 Phase, Automation & Breaker Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis Of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis shown on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks, which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

NTPC is proposing to undertake a project to acquire a two megawatt (MW) mobile diesel generator to be based in Yellowknife. The purpose of this new generator is to provide an immediate increase to the available capacity of the Snare-Yellowknife system. Jackfish has a number of generators that are nearing the end of their useful life and have a significant risk of failure, with some units having installation dates from the 1970s. The mobile generator would be used as a backup in case of a failure of some of the current diesel generators, which is considered likely given the age of the units.

The low water levels on the Snare hydro system required NTPC to use the diesel based backup system, which required the Jackfish diesel generator sets (gensets) to be run on a continuous basis.

The Jackfish diesel plant has historically been used as a backup plant for hydro generation and was not intended to be run continuously on a long-term basis. As a result, the plant received the level of maintenance and capital required to operate as a back-up facility.

BACKGROUND

As a result of water flows, NTPC has been dispatching material diesel generation since July 2014. The requirement for diesel generation continued into 2015 and may continue into future years if low water conditions persist longer than normal. This low water event has required the Jackfish diesel gensets to be operated for continuous periods that are much longer than their intended purpose as backup generation. This has placed considerable strain on the current aging diesel gensets, increasing the importance of adding backup diesel generation capacity.

The 2 MW backup unit would perform two distinct functions in the NTPC system by providing emergency capabilities and backup generation. NTPC has traditionally maintained a set of diesel backup generating units for deployment in the case of emergencies, generation capital projects, etc. The addition of a 2 MW unit would complement the emergency or portable gensets that are available.

Additional diesel generation resources are required for Yellowknife as other old units move towards retirement and must be replaced. This can lead to lengthy periods with less than a full complement of diesel units. All road accessible communities in the Thermal region will also benefit. The storage of the mobile unit in Yellowknife would allow the genset to be deployed to the Deh Cho communities in the event of an emergency, as well as to other road accessible regions.



Northwest Territories Power Corporation
Business Case
North Slave 2 MW Mobile Genset

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The “do nothing” approach would force the Corporation to rent diesel generators in the event of an emergency situation or equipment failure at Jackfish.

Option 2: Rental Generation

This option would involve renting a 2 MW generation unit and deploying it to Yellowknife. It would fulfill the immediate need to provide backup capacity for the Snare-Yellowknife system.

Various options for renting from 2 MW to 10 MW have been considered. The proposals received indicate rental costs of \$110,000 per month for each 2.0 MW unit. There is also a one-time mobilization/demobilization fee of \$160,000. Please see Table 1 for an analysis on the potential cost of the rental generation.

If the duration of the drought is assumed to last 6 months, the total rental unit cost would be estimated at \$820,000. In addition, NTPC would still not own the asset and have it available for future use despite spending a considerable amount.

Table 1 - Sensitivity Analysis on use of Rental Generation

Total Cost for Usage of Rental Generation (\$000's)							
Number of Months (A)	3	4	5	6	7	8	9
Rental Fee per Month (B)	\$ 110	\$ 110	\$ 110	\$ 110	\$ 110	\$ 110	\$ 110
Total Rental Fee (C = A X B)	\$ 330	\$ 440	\$ 550	\$ 660	\$ 770	\$ 880	\$ 990
Mobilization / Demobilization Fee	\$ 160	\$ 160	\$ 160	\$ 160	\$ 160	\$ 160	\$ 160
Total Cost of Rental Unit	\$ 490	\$ 600	\$ 710	\$ 820	\$ 930	\$1,040	\$1,150

Option 3: Purchase 2 MW Mobile Generator

This option would involve the purchase of a 2 MW generation unit and deploying it to Yellowknife. It would fulfill the immediate need to provide backup capacity for the Snare-Yellowknife system. This option has the following key benefits:

- Increased reliability for Yellowknife.
 - The new unit could be immediately deployed to Yellowknife to support the Jackfish diesel gensets, which were running continuously during the low water events experienced in 2013/14 and 2014/15. The hours of diesel operation on NTPC's



Northwest Territories Power Corporation
Business Case
North Slave 2 MW Mobile Genset

- existing units can be reduced, helping reduce the pressure for overhauls during the coldest periods of the winter.
 - The Jackfish diesel gensets received only minor capital investments over the last decade, which was in line with its primary role as a backup facility. This resulted in lower levels of plant reliability that were acceptable for its backup function. The new mobile genset will provide backup power and improve the plant's overall reliability.
 - The downtime duration would be reduced in the event of a diesel genset failure. Multiple failures in the Jackfish plant would require support from rental generation, which requires 48 hours to mobilize and is more costly to operate.
- Support for future major overhauls.
 - NTPC has major overhauls planned in the coming years that may require back-up power. Temporary generation is required when completing overhauls, and owning the mobile unit would avoid the associated rental generation costs.
 - Greater flexibility in planning these activities would be gained as owning the asset removes a complicating element of overhaul project plans and ensures generator availability.
- Contingency planning / emergency response.
 - As emergencies arise, NTPC would have the ability to deploy the unit to provide reliable power supply to communities affected.
 - Mobile generation units are long-term resources that are available to help address contingencies and emergencies in road serviced areas throughout the Corporation. Communities in the Deh Cho area and other thermal communities could be supplied with temporary power relatively quickly in the event of an emergency.
 - It is an industry common practice for utilities to have mobile gensets as standby units that can be deployed as required.

COST ESTIMATE

The purchase price of the unit is \$1.6 million. This cost includes a base price for the diesel engine unit and expected overhead costs.

Please note for the purposes of analysis we have excluded the expected O&M costs from the purchase and rental option. These costs are expected to be approximately equal for both options. As part of any rental agreement, NTPC would be obligated to maintain the unit while utilizing it.



Northwest Territories Power Corporation
Business Case
North Slave 2 MW Mobile Genset

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2015/16	\$1,441,400	\$0	\$158,600	\$1,600,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$1.6M
- Amortization rate of 4.04%
- Return on Ratebase of 7.18%
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.483%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
North Slave 2 MW Mobile Genset

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$1,600	\$2,000	\$2,400	\$3,200
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$65	\$81	\$97	\$129
Return on Ratebase (\$000)	\$115	\$144	\$172	\$230
Sub-Total: Revenue Requirement Increase (\$000)	\$180	\$224	\$269	\$359
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$180	\$224	\$269	\$359
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.483%	0.604%	0.724%	0.966%

SUMMARY OF BUSINESS CASE RATIONALE

Given the low water conditions on the Snare hydro system, NTPC has been forced to run the Jackfish backup facility to provide power to customer in Yellowknife and surrounding areas.

The Jackfish plant received the maintenance and capital required to operate as a back-up facility, and was not originally intended to be operated continuously on a long-term basis. Jackfish has a number of very old generators that are likely to fail under continuous operating conditions.

To meet its obligation to provide customers with reliable power, NTPC's preferred option is to acquire a new mobile generator to deploy immediately to the Yellowknife area. NTPC has examined two ways of obtaining the generator that is required, renting a unit or buying one.

The Corporation has determined that purchasing a new mobile genset is the superior option. While more expensive in the short term, \$1.6M for outright purchase vs. an estimate of \$0.82M for rental, a purchase has a number of advantages that outweigh the cost. The South Slave system has major overhauls planned in the coming years and temporary generation will be required to complete the overhauls. Owning the asset would allow the Corporation to avoid rental generation



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Business Case
North Slave 2 MW Mobile Genset

costs and provide greater flexibility in planning future engine overhaul activities. Furthermore, the new mobile genset would allow improved contingency planning and emergency response, as NTPC would have the ability to deploy the unit to provide reliable power supply to communities affected. Lastly, the drought season may last longer than anticipated or equipment outages may force the need to continue using a rental unit. If the use of the rental generator exceeds the one year, the costs of either option begin to converge, making purchase the superior option.

RECOMMENDATION

To meet its commitment to provide reliable power to its customers, NTPC recommends the purchase of a two megawatt mobile diesel generator as outlined in option 3. The total costs to complete the project are estimated to be \$1.60M.



Northwest Territories Power Corporation
Business Case
North Slave 2 MW Mobile Genset

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on pages 2 and 5.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
North Slave Protective Relay Upgrades

NEED FOR PROJECT

NTPC is proposing to undertake a project to replace obsolete electromechanical with electronic digital relays. Over the years, it has been observed that the sequence of events during power failures did not provide the desired operational result. Power interruptions were much more numerous and more extensive than should be the case. This has had an impact on operating costs, revenue and customer confidence.

It is costly and more operationally challenging to maintain obsolete relays, which have the additional need for periodic calibration. Modern digital relays will also address the issues of better communication between relays, which is required to provide better relay response to power failure events.

BACKGROUND

The largest power system within the NTPC network is the Snare-Jackfish-Bluefish system, otherwise known as the North Slave system. This system provides generation and transmission to the Yellowknife region.

In fiscal 2012, a review of the North Slave Power System Protection Scheme was carried out by Electric Power Systems Inc (EPS). The report identified various anomalies in the protection schemes as well as existing mismatches between old and obsolete electromechanical relays and electronic relays. The report also identified problems and limitations in setting those relays, in order to achieve good relay co-ordination and selective isolation. The report strongly suggested replacing of the old and obsolete relays with modern digital relays.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

This option will not address the existing lack of control over the North Slave Power system due to obsolete and incompatible equipment. NTPC risks continued power interruptions and the resulting operating and maintenance costs, revenue loss and loss of customer confidence.

Option 2: Replace Obsolete Relays with Digital Multifunction Relays

The relays identified in the EPS report will be replaced with new digital multifunction relays. The proposed replacement plan is a 4-year phased program, briefly outlined as follows:

Year 1 - Snare-Jackfish and Bluefish-Ingraham-Jackfish System relay replacement.

Year 2 - Snare Hydro Generation complex relay replacement.

Year 3- Jackfish Substation, K-Plant, EMD Plant, Bluefish Generation/Substations,



Northwest Territories Power Corporation
Business Case
North Slave Protective Relay Upgrades

Franks Channel relay replacement.
Year 4 - Debugging and co-ordination of equipment.

The main benefits of the project are as follows:

- The electronic relays allow data to be downloaded and analyzed, providing the engineering group with information regarding the cause of each outage. The relays can then be reprogrammed based on the data provided to improve system stability and reliability. Mechanical relays do not provide the engineers with any information except that the relay was tripped but the cause is unknown.
- The new relays provide remote access capability thereby allowing head office staff to assist in the trouble shooting process, which will shorten the duration of outages.
- Improved relay response time during outages.
- Reduction in operational cost as less time will be spent calibrating the relays.

COST ESTIMATES

Table 1 – Budget Estimates

Design

Description	2013/14 Budget
Payroll Regular	\$5,000
Fringe Benefits	\$1,000
Consultants Lump Sum	\$77,000
Transportation	\$10,000
Accommodations	\$6,500
Meals	\$7,500
Total	\$107,000

Construction / Purchasing



Northwest Territories Power Corporation
Business Case
North Slave Protective Relay Upgrades

Description	2013/14 Budget
Payroll Regular	\$6,500
Fringe Benefits	\$1,000
Consultants Lump Sum	\$45,000
Contractors Lump Sum	\$250,000
Transportation	\$20,000
Accommodation	\$13,000
Meals	\$15,000
Fuel for Type 5 Jobs	\$0
Equipment Rental	\$5,000
Freight	\$10,000
Contingency 15%	\$83,000
Sub-Total	\$448,500
Total – All phases	\$555,500

Project Estimated Costs

Budget Year	Annual Budget Estimate	IDC	Overhead	Total Annual Cost
2014	555,500		83,475	638,975
2015	962,000		145,000	1,107,000
2016	1,114,000		171,000	1,285,000
2017	405,000		62,000	467,000
			Total Project Cost	\$3,498,975

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 47 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$3.499M.
- Amortization rate of 2.15%.
- Return on Ratebase of 7.18%.
- Allocation costs to Snare Zone only.



Northwest Territories Power Corporation
Business Case
North Slave Protective Relay Upgrades

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.878%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost	\$3,499	\$4,374	\$5,248	\$6,998
Amortization Period (Approx. Years)	47	47	47	47
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense	\$75	\$177	\$212	\$283
Return on Ratebase	\$251	\$314	\$377	\$502
Sub-Total: Revenue Requirement Increase	\$326	\$491	\$589	\$785
Less: Estimated O&M Savings				
Total Revenue Requirement Impact	\$326	\$491	\$589	\$785
Snare Zone Revenue Requirement	\$37,174	\$37,174	\$37,174	\$37,174
Average Percentage Rate Increase	0.878%	1.320%	1.584%	2.112%

SUMMARY OF BUSINESS CASE RATIONALE

The electromechanical relays in the North Slave System have become obsolete and are



Northwest Territories Power Corporation
Business Case
North Slave Protective Relay Upgrades

approaching the end of their useful life. Replacing the old relays with new digital multifunction relays is essential for system reliability as outlined in the EPS report. Maintaining and calibrating the old relays will become more increasingly costly with no anticipated return with respect to reliable operation. The new relays will require less maintenance and provide better system protection thereby increasing the reliability of the North Slave Power System.

RECOMMENDATION

It is recommended that NTPC proceed with the proposed project as outlined in option 2 at an estimated capital cost of \$3.499M.

Attachment A



Northwest Territories Power Corporation
Business Case
North Slave Protective Relay Upgrades

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses Estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>

2015/16 Business Cases



NEED FOR PROJECT

The Corporation is proposing to complete a project to install a new Computer Management and Maintenance System (CMMS) and integrate this software with the Corporation's current financial systems. This new system would replace the existing computer maintenance system. The full integration of a CMMS with NTPC's financial systems would streamline a number of internal processes and drive improvements in the reliability of the utility system. NTPC is expected to realize significant cost savings in maintenance labor, parts and materials.

BACKGROUND

NTPC's currently uses a computer maintenance system software package called Maintenance Control System (MCS). The software is used to forecast and track equipment maintenance throughout the Corporation. The current system has a number of limitations as it is only able to track engine maintenance. The current system is not configured to record transmission, distribution, and plant auxiliary equipment maintenance. It is also not capable of generating and tracking custom work orders in response to outages and other unplanned events.

The most recent version of the software was published in 2002. This software does not offer compatibility with the current IT infrastructure of the Corporation, as it is not designed for operation on the current operating systems and network environment of NTPC. A replacement maintenance system will be required.

Given the need to replace the current MCS system, the Corporation created a taskforce dedicated to the selection and implementation of a new computer maintenance system. The taskforce membership covers all the areas impacted by this system including IT, Finance, Operations, and Asset Management. In order to assist the team in assessing the various offerings from vendors, the team identified the key requirements of a new system. They are as follows:

Specific requirements:

- Asset information tracking to track all NTPC assets.
- Asset planning.
- Work order management for inventory, purchasing, scheduling and subcontractor management.
- Recording asset downtime (e.g. generators and transformers).
- Maintenance log to record the historical maintenance events on assets.
- Financial integration with financial systems.



ANALYSIS OF OPTIONS

Option 1: Do Nothing

The current MCS has reached the end of its useful life. There is significant risk to continuing to use the current application as vendor support has run out and integration with existing systems is becoming more difficult and requires manual intervention.

The MCS product also lacks the capabilities to fully support the Corporation's requirements. The current software cannot be used to track equipment that is not part of the generator units. This means a large proportion of the Corporation's assets are not being systematically tracked and maintained at the optimal level. Therefore, the do nothing option is not viable and a new maintenance application is required.

Option 2: Selection and Installation of CMMS

Estimated Costs: \$3,600,000

This option would involve the selection and installation of a new CMMS. The Corporation evaluated several CMMS software applications based on the requirements that were identified by the taskforce. Based on the evaluation of the CMMS applications, NTPC determined that Guide TI was the best CMMS solution. Guide TI software has the following capabilities:

- Asset information tracking at the level required by Divisions and linkage to financial asset tracking.
- Asset planning.
- Asset maintenance work order management including triggering and managing the following work order related activities:
 - Inventory handling
 - Purchasing
 - Scheduling
 - Work planning
 - Analytics
 - Work tracking
 - Asset maintenance budgets
 - Sub-contractor management on work orders with qualification and certification validation.
 - Accurately recording asset downtime.
- Maintenance log:
 - Accurately recording historical maintenance events, repairs and failure events so common strategies can be applied to like equipment corporate wide.
 - Consecutive equipment hour reads allows for accurately predicting current and future maintenance events (algorithmic solution).



The implementation of CMMS would be a multi-year effort as all Corporation facilities would need to have the software installed. As a result, the Corporation has elected to pursue implementation using the following phased approach:

- Phase I - CMMS selection and implementation at two pilot plants.
- Phase II - CMMS would be rolled out to all other facilities.

This phased approach offers a numbers of advantages. In the event that the initial pilot is not successful, the Corporation can terminate the project and avoid significant expenditures for a product that is not effective. The installation of a new standalone CMMS offers a number of benefits but does not fully utilize the capabilities of the Guide TI software. These benefits are as follows:

- Asset Life Improvements - Maintaining equipment properly substantially extends the operating life and prevents premature asset failures. CMMS will ensure critical maintenance activities are completed before equipment sustains unnecessary damage or failure.
- Asset Performance - Scheduling preventive maintenance tasks with CMMS makes sure assets are running at optimal performance.
- Emergency Maintenance Reductions - Fewer hours are required to maintain equipment when preventative practices are employed. CMMS enables proper maintenance scheduling. Minor issues are addressed in a timely manner, reducing the chance that they become major issues and more costly.
- Audit and Regulatory Reporting - CMMS software keeps all maintenance and asset management records stored electronically. Important records can be accessed as required for compliance reporting.
- Standardization/Safety - CMMS will help standardize maintenance processes. Standardized processes for how to inspect, repair, and properly maintain equipment can be captured by uploading procedures into CMMS. Uniform maintenance procedures contribute to uniform maintenance work and enhanced safety of staff.

Option 3: Selection and Installation of CMMS with Financial Integration

Estimated Costs: \$4,471,000

This option would involve the selection and installation of a CMMS system, as well as its integration with the Corporation's financial systems. This would involve using the same Guide TI software identified in the previous option and would fully utilize the capabilities of the software.

As with the previous option, this would be a multi-year effort as all Corporation facilities would need to have the software installed and subsequently integrated with existing financial systems. The Corporation would also use a phased approach for implementation.

- Phase I - CMMS system selection and implementation at two pilot plants.
- Phase II - CMMS would be rolled out to all other facilities.
- Phase III - Integration of CMMS with financial systems.



Northwest Territories Power Corporation
Business Case
CMMS

As with the previous option, if the initial pilot is not successful, the Corporation can terminate this project and avoid significant expenditures for a product that is not effective. Assuming Phase I does succeed, the Corporation can roll out CMMS in Phase II and begin to realize some benefits from the project prior to completion of the project in Phase III. This option includes all the benefits outlined in Option 2 along with the following additional benefits:

- Parts and Inventory Management - Better planning and less emergency repairs reduce the need to carry as much spare part inventory. CMMS inventory management will help manage inventory levels and set reorder points on specific items.
- Enhanced Analytics - CMMS can be used by management to track key performance indicators (KPIs) such as Mean time between failures (MTBFs), work order processing speed/capacity and customer satisfaction. These data can also be used by the maintenance managers to plan and schedule maintenance activities, improving maintenance performance.
- Purchasing – Automation of purchase order (PO) generation reduces PO errors caused by human errors from the current manual PO process.

COST ESTIMATES

Table 1 – Budget Estimates

Description	2013/14	2014/15	2015/16
Payroll	\$272,000	\$598,000	\$403,000
Payroll OT	\$28,000	\$54,000	\$45,000
Payroll burdens	\$79,000	\$143,000	\$101,000
Contractors Lump Sum	\$556,000	\$446,000	\$639,000
Transportation	\$47,000	\$61,000	\$33,000
Accommodation	\$26,000	\$26,000	\$21,000
Meals	\$9,000	\$9,000	\$9,500
Micro-Computers	\$25,000	\$99,000	-
Total	\$1,042,000	\$1,436,000	\$1,251,500

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$1,042,000	\$30,000	\$157,500	\$1,229,500
2014/15	\$1,436,000	\$76,500	\$207,500	\$1,720,000
2015/16	\$1,251,500	\$76,500	\$193,500	\$1,521,500
Total Cost				\$4,471,000



RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 15 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$4.471M
- Amortization rate of 6.52%
- Return on Ratebase of 6.88%
- Allocation of costs to entire region

Given the above assumptions, the average rate impact of the project for NTPC's customers is estimated at 0.566%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$4,471	\$5,589	\$6,707	\$8,942
Amortization Period (Approx. Year)	15	15	15	15
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$292	\$364	\$437	\$583
Return on Ratebase (\$000)	\$308	\$385	\$461	\$615
Sub-Total: Revenue Requirement Increase (\$000)	\$599	\$749	\$899	\$1,198
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$599	\$749	\$899	\$1,198
Total Revenue Requirement – All Zones (\$000)	\$105,840	\$105,840	\$105,840	\$105,840
Average % Rate Increase	0.566%	0.708%	0.849%	1.132%



SUMMARY OF BUSINESS CASE RATIONALE

The Corporation's current MCS has reached its end of life and a new replacement maintenance system is required. There is no vendor support for this product and integration with existing systems is becoming more difficult and requiring manual intervention. The MCS product also lacks the capabilities to fully support the Corporation's requirements. The current software can only track generator equipment, which results in a large proportion of corporate assets (e.g., transmission assets) not being systematically tracked and maintained at optimal levels.

The Corporation assembled a cross functional task force to select a suitable replacement maintenance system, with members from key areas such as IT, Finance, Operations, and Asset Management. The team identified the requirements of a new system and then identified Guide TI as a software solution with a strong track record and ability to meet these requirements.

The CMMS would be implemented using a phased approach, with the system piloted in two plants and subsequently rolled out to all other NPTC facilities if the initial pilot proves successful. Once CMMS is implemented corporate wide, this system will be integrated with the financial system. This phased approach will allow for termination of the project in the early stages if the system does not perform as expected. This approach also allows some of the benefits to be realized, before the project is completed. The full set of benefits that are anticipated once the CMMS software is fully implemented and integrated with the Corporation's financial systems are:

- Asset Life Improvements - Critical maintenance activities are completed before equipment sustains unnecessary damage or failure, extending operating life.
- Asset Performance - Scheduling maintenance with CMMS makes sure assets are running with optimal performance.
- Emergency Maintenance Reductions - CMMS enables proper maintenance scheduling and ensures that minor issues are addressed in a timely manner, reducing the chance that they become major issues and more costly to address.
- Parts and Inventory Management - CMMS inventory management will help manage inventory levels and reduce spare part inventory levels.
- Audit and Regulatory Reporting - CMMS stores maintenance and asset management records electronically, allowing important records to be accessed for compliance reporting.
- Standardization/Safety - CMMS will help standardize maintenance processes, which contribute to uniform maintenance work and enhanced safety.
- Enhanced Analytics - CMMS can be used by management to track performance KPIs and allow managers to plan and schedule maintenance activities.
- Purchasing – Automation of PO generation reduces PO errors.

All of these items will provide meaningful benefits to NTPC and its customers. Maintenance and related processes will be improved substantially. This will translate into improvements in the reliability of the utility system and derive potentially significant cost savings.



RECOMMENDATION

The Corporation recommends proceeding with option 3 to install a CMMS system and integrate this application with the Corporation's existing financial systems. The total costs to complete the project are estimated to be \$4.471M.



Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

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Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 5.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation Business Case

Inuvik – 5kV Breaker Replacement Rotational Program for EMD Plant

NEED FOR PROJECT

The Corporation is proposing to undertake a project to upgrade the generation and feeder 5kV breakers that have reached the end of their useful life and are now obsolete. Replacement parts are becoming difficult to procure and new parts are no longer manufactured. The breakers are becoming more problematic to operate, thus putting the generation and feeder equipment at risk of failure and extended outage durations.

This project entails a breaker replacement program on a rotational five year program with one breaker to be replaced per year for five years. A spare breaker can be sourced upgraded to modern day vacuum type breakers that will fit into the existing switchgear breaker cell and once that breaker is replaced the existing breaker can be retrofitted for the next breaker cell for the following year.

BACKGROUND

The EMD Plant in Inuvik was originally constructed in the early 1970's and was reconstructed in 1984 after a fire. The power plant was reconstructed utilizing the same switchgear and breakers. Presently, all the switchgear cells (3 generator and 2 feeder cells) have undergone upgrades including relay protection to modern digital protection relays and are in nearly new condition.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The existing generator and feeder breakers have reached the end of their useful life leaving NTPC's generation and feeder equipment at risk of breaker failure, arc flash incidents and extended outage durations. Therefore the do nothing option is not recommended.

**Option 2: Breaker Replacement Program****Estimated Costs: \$628,000**

This option entails a breaker replacement program that will replace one breaker per year over a five year period. The Corporation will purchase a used breaker matching the same make and model, which will be retrofitted with modern vacuum type breakers to allow for a seamless removal and replacement of the existing breaker. Once the new breaker is installed the existing breaker that was removed will be retrofitted to a vacuum type breaker for the following year.

The benefits of option 2 are summarized as follows:

- The replacement of the generation and feeder breakers will bring the entire switchgear cells up to “as new” condition providing reliable operation of the breakers.
- The vacuum type breakers are an industry best practice with parts readily available.
- The new breakers are longed lived assets with a useful life of over 30 years.
- Reduced cost of replacement parts and easy to procure.
- All the generation and feeder breakers are of the same make and model allowing for the interchangeability of all the breakers into the existing switchgear cell cradles, which will allow for minimal impact on operations and the generation and feeder equipment.

Option 3: Generation & Feeder Switchgear Cells Replacement**Estimated Costs: \$1,750,000**

Option 3 would entail the replacement of the entire generation and feeder switchgear cells with new switchgear cabinets, modern digital relays, ancillary equipment, wiring, cabling, high voltage bus and breakers, in one construction and installation year. During the installation of the new switchgear, the entire power plant would be out of service for duration of approximately 60 days leaving the Inuvik K-plant as the only power generation source. Due to the feeder distribution configuration at the Inuvik power plant site, the two feeder cells in the EMD plant would have to be paralleled with two feeder cells in the K-Plant until the project was completed.



Northwest Territories Power Corporation
Business Case

Inuvik – 5kV Breaker Replacement Rotational Program for EMD Plant

COST ESTIMATES

Table 1 – Budget Estimates

Description	2013/14	2014/15	2015/16	2016/17	2017/18
Payroll Regular	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
Payroll O/T	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000
Fringe Benefits	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000
Consultants Lump Sum	\$28,500	\$28,500	\$28,000	\$28,000	\$28,000
Contractors Lump Sum	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
Travel	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000
Accommodations	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000
Freight	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000
Breaker	\$32,500	\$32,500	\$32,500	\$32,500	\$32,000
Generator Switchgear	\$21,000	\$21,000	\$21,000	\$21,000	\$21,000
Overhead Conductors	\$4,000	\$4,000	\$4,000	\$4,000	\$4,000
Contingency 10%	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
TOTAL	\$110,000	\$110,000	\$109,500	\$109,500	\$109,000

Project Estimated Cost:

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$110,000	\$3,000	\$13,000	\$126,000
2014/15	\$110,000	\$3,000	\$13,000	\$126,000
2015/16	\$109,500	\$3,000	\$13,000	\$125,500
2016/17	\$109,500	\$3,000	\$13,000	\$125,500
2017/18	\$109,000	\$3,000	\$13,000	\$125,000
Total Project Cost				\$628,000



RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates for Diesel Plants. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.628M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.096%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$628	\$785	\$942	\$1,256
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$25	\$32	\$38	\$51
Return on Ratebase (\$000)	\$31	\$38	\$46	\$61
Sub-Total: Revenue Requirement Increase (\$000)	\$56	\$70	\$84	\$112
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$56	\$70	\$84	\$112
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.096%	0.120%	0.144%	0.192%



SUMMARY OF BUSINESS CASE RATIONALE

The generation and feeder 5kV breakers have reached the end of their useful lives and must be replaced. The existing switchgear cells are in excellent condition with modern digital relay protection and to complete the reliability of the switchgear cells the breakers require replacement. Replacing the breakers on a five year rotational program will minimize the impact on the operations of Inuvik. The Corporation views this as a very important aspect to the option given the operational problems caused by the old breakers. The industries best practice of vacuum breakers will allow 30+ years of continuous service with readily available parts and problematic free operation. The project's budget is expected to be distributed over the five year period of the project and each breaker is expected to have similar cost.

RECOMMENDATION

The Corporation recommends proceeding with option 2, implementing a breaker replacement program for the aging generation and feeder breakers at the Inuvik EMD plant. The total costs to complete the project are estimated to be \$0.628M.



Northwest Territories Power Corporation
Business Case

Inuvik – 5kV Breaker Replacement Rotational Program for EMD Plant

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NEED FOR PROJECT

The purpose of the project is to replace the current T3 transformer at the Jackfish plant with a suitably designed replacement to meet the following needs:

- 1) Increased capacity
 - Connection point for modular generators for 2016/17 winter.
 - Low water conditions are expected to prevail for at least an additional year and therefore the Jackfish facility will continue to be run in a continuous fashion. The Mirrlees generator sets (gensets) have been in operation for over 40 years and are due to be replaced in the coming years. As such, modular diesel generation would provide backup generation in the near term and provide a replacement solution longer term.
- 2) Long term planning and renewables
 - Provides a connection point for the permanent Mirrlees replacement, while maintaining the Required Firm Capacity (RFC) at the Jackfish Lake plant.
 - Future installation of a BESS (Battery Energy Storage System) and/or renewable sources.
- 3) Transformer redundancy
 - Currently a loss of any transformer at the Jackfish substation will put Jackfish below PUB RFC requirements.
 - This project increases capacity by allowing a connection / switching to other plants (EMD, K-Plant), hence providing redundancy in the event of transformer failure.

Project specifications to meet these requirements are as follows:

- Increase transformer T3 capacity from 6.6 MVA to 16 MVA considering that an 8 MVA battery storage unit would be connected in the future.
- A substation structure to support busbar, cables, switches to connect the transformer to multiple power sources (e.g. modular gensets, 8 MVA Battery storage, existing 34.5kV station bus, a spare generator system).

BACKGROUND

Jackfish Plant

The generation capacity at Jackfish includes two 5.2 MW Mirrlees gensets. These units were installed in 1970 and 1974 and have about 73,000 and 47,000 hours of run time respectively. They are now due for major overhauls at a total estimated cost of \$5M to \$6M. In addition, due to the age of the units, failures have been occurring frequently as the units approach the end of their



Northwest Territories Power Corporation
Business Case Draft
Jackfish – T3 Replacement

useful lives. As a result, NTPC has developed a capital plan that includes the replacement of these units.

In conjunction with the Mirrlees overhaul, NTPC requires a connection point in the Jackfish substation for an additional 5-6 MW of generation. T3 is a 12 kV/34.5 kV, 6.6 MVA transformer that was used for the former Rustin Plant (which is now decommissioned). The transformer was installed in 1988 and has been out of service since 2005. Installation of a new transformer was considered separately from the Mirrlees replacement project due to its interconnection to other units and the extended capacity to be used for future battery and other renewable options.

The Jackfish facility has three power plants, Cat plant, EMD plant and the Mirrlees plant. Each plant feeds the Jackfish substation via a dedicated transformer (T10, T2 and T3, respectively). There is currently no redundancy for these transformers, meaning that a failure of one of the above transformers would result in the inability to meet the RFC requirements.

Renewables

Recent low water conditions have resulted in much higher than normal diesel generation. Stakeholders have expressed the desire to increase the proportion of renewable generation on the Snare system while maintaining reliability. This requires flexibility in the design of the transformer to be purchased. The most likely scenario is the connection of an 8 MVA battery bank to the transformer in addition to modular units. Batteries would provide short term backup and limit outages but would also provide system stability when connecting renewables (wind / solar) sources that are intermittent in nature. This requires additional capacity and physical space that could not be accommodated through the purchase of a similar replacement transformer.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option leaves NTPC without any transformer redundancy, without flexibility to add additional units and without renewable connections / battery storage.

Option 2: Replace T3 with 5MVA Transformer

Estimated Cost: \$300k

- The transformer T3 will be replaced with a new 5 MVA transformer (i.e., like for like).
- The current transformer foundation, the secondary cable and cable tray system will be used without any modification.
- Temporary modular gensets will be connected to the existing cable system.

Replacing the existing T3 transformer with an identically sized unit would provide a temporary replacement and mitigate reliability concerns in the short term. It would not, however, be flexible enough to allow further installations or to accommodate renewables in the future that require



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Jackfish – T3 Replacement

battery storage. This could significantly increase the costs should additional capacity be required, or if the installation of battery storage occurs. The original capacity was not suitable for the provision of transformer redundancy.

Option 3: Replace T3 with 16MVA Unit & Support Structures for Future Installations
Estimated Costs: \$1.28M

This option is to replace T3 with an appropriately sized transformer to provide redundancy for the system and flexibility for the Mirreles replacements, including the installation of battery storage and renewable technologies.

COST ESTIMATES

The total cost estimate of replacing the T3 substation transformer is \$1.3M, including direct and indirect costs and a contingency of 20%.

Table 1 – Budget Estimates

Description	2015/16
NTPC Labour	\$25,000
Consultants Lump Sum	\$32,000
Contractors Lump Sum	\$65,000
Expenses (Travel etc.)	\$6,000
Interest During Construction	\$0
Controllers/Compensators/Lightning Protection	\$747,000
Contingency (20%)	\$175,000
Total Current Year Project	\$1,050,000

Project Estimated Cost:

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2015/16	\$1,050,000	\$0	\$231,000	\$1,281,000
Total				\$1,281,000

In addition, a full Project Safety Risk Analysis has been conducted and controls are in place to mitigate identified hazards. Project risks related to procurement and operations have been mitigated with a budgeted contingency.



RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 47 years at the currently approved GRA amortization rates for transmission plants. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$1.28M.
- Amortization rate of 2.15%.
- Return on Ratebase of 7.18%.
- Allocation of costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.32%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$1,281	\$1,601	\$1,922	\$2,562
Amortization Period (Approx. Year)	15	15	15	15
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$28	\$34	\$41	\$55
Return on Ratebase (\$000)	\$92	\$115	\$138	\$184
Sub-Total: Revenue Requirement Increase (\$000)	\$120	\$149	\$179	\$239
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$120	\$149	\$179	\$239
Total Community Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.322%	0.402%	0.482%	0.643%



SUMMARY OF BUSINESS CASE RATIONALE

The T3 transformer at the Jackfish power plant in Yellowknife no longer meets the requirements of the Corporation. This transformer needs to be replaced with a higher capacity unit that will provide a connection point for new modular generators. In addition, the project will allow the Corporation to initiate long term planning with the transformer, providing a connection point for installation of renewable sources and new diesel generation units. It will also provide transformer redundancy, which is required given the loss of a transformer at the Jackfish plant would inhibit the plant from meeting its RFC requirements.

Stakeholders and the public have expressed a strong desire to introduce a greater proportion of renewable generation into the Snare system to mitigate increasing diesel costs and reduce greenhouse gas emissions. The replacement of the T3 transformer provides an opportunity to install sufficient flexibility in the substation structures to allow connection of BESS and renewable sources. The expanded capacity also provides flexibility should additional temporary diesel generation be required, as well as the ability to install additional modular units in the future.

RECOMMENDATION

It is recommended to proceed with option 3, the installation of a 16 MVA transformer and associated substation structures.



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NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to complete a refurbishment on the T10 transformer at the Jackfish plant.

In 2013, just before the onset of winter, a fault occurred at a Jackfish substation that resulted in damage being caused to transformer T10. As a result of the damage, transformer T10 was no longer operational with several cables and switches at the transformer sustaining burn damage.

Jackfish has three power plants, K-plant, EMD-plant and CAT-plant. With the damage sustained to the T10 transformer, the CAT plant became effectively disconnected from the grid meaning the plant would no longer be able to supply power to the Yellowknife grid.

The CAT plant provides a significant amount of the capacity of the Jackfish plant and is a critical part of the overall Jackfish plant in its ability to serve as an effective backup facility.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

Failure to complete the refurbishment program on the T10 transformer would result in the CAT plant at Jackfish remaining disconnected from the grid, and unable to provide generation capacity. In an event where backup power was required, such as the recent low water conditions, the Jackfish plant would not be able to meet current Yellowknife demand thereby making option #1 not viable.

Option 2: Refurbishment of T10 Transformer Estimated Costs: \$447,000

This option would involve completing a refurbishment of the T10 transformer and the associated electrical systems. This would bring these systems back to a standby condition. It would mean that the CAT plant at Jackfish would be effectively reconnected to the Yellowknife grid.

This would allow the CAT plant to contribute to the available capacity of the overall Jackfish plant as needed. The key steps in completing the refurbishment include the following:

- Testing of transformer T10 and associated electrical system to identify defects
- Replace defective parts and refurbish the transformer to bring it back to service
- Replace the damaged cable terminations
- Testing and commissioning of cables, transformer and switches
- Oil changing and filtrations of transformer oil under vacuum and heat
- Servicing relays and modifying wiring of relay panels in the CAT plant



Northwest Territories Power Corporation
Business Case
Jackfish T10 Refurbishment

COST ESTIMATES

Table 1 – Budget Estimates

Description	2013/14	2014/15	2015/16
Payroll Regular	49,000	4,000	-
Payroll Overtime	27,000	1,500	-
Payroll Fringe Benefits	12,000	500	-
Consultants Lump Sum	14,000	-	-
Contractors Lump Sum	146,000	-	-
Transportation	7,000	-	-
Accommodation	6,000	-	-
Meals	3,000	-	-
Construction Camps	2,000	-	-
Freight	8,000	-	-
Accessory Electrical Equipment	2,000	-	-
Transformers	12,000	-	52,000
Total Base Project Estimate	\$288,000	\$6,000	\$52,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$288,000	\$8,000	\$49,000	\$345,000
2014/15	\$6,000	\$18,000	\$2,000	\$26,000
2015/16	\$52,000	\$13,000	\$11,000	\$76,000
Total				\$447,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 47 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.447M
- Amortization rate of 2.15%
- Return on Ratebase of 7.18%
- Allocation of costs to Snare Zone



Northwest Territories Power Corporation
Business Case
Jackfish T10 Refurbishment

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.112%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$447	\$559	\$671	\$894
Amortization Period (Approx. Year)	47	47	47	47
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$10	\$12	\$14	\$19
Return on Ratebase (\$000)	\$32	\$40	\$48	\$64
Sub-Total: Revenue Requirement Increase (\$000)	\$42	\$52	\$63	\$83
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$42	\$52	\$63	\$83
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.112%	0.140%	0.168%	0.224%

SUMMARY OF BUSINESS CASE RATIONALE

The T10 transformer at a Jackfish substation was damaged in 2013 resulting in the CAT plant at Jackfish becoming effectively disconnected from the Yellowknife grid. The CAT plant provides a significant amount of the capacity of the overall Jackfish plant and is required to meet current Yellowknife power demand.

The Corporation is proposing to complete a refurbishment of the T10 transformer to reconnect the CAT plant to the Yellowknife grid and make it operational. This will enable the Jackfish plant to serve as an effective backup and meet Yellowknife power demand as needed.

RECOMMENDATION

The Corporation recommends proceeding with option 2 to refurbish of the T10 transformer at the Jackfish plant. The total costs to complete the project are estimated to be \$0.447M.



Northwest Territories Power Corporation
Business Case
Jackfish T10 Refurbishment

Attachment A

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NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to install and commission a new fuel system for the Jean Marie River power plant. The Jean Marie River plant currently has three diesel generators (gensets) capable of producing a total of 266 kWh. This includes the following units:

- G1 — 106 kWh Deutz TCD914LO6 (installed in 2014)
- G2 — 90 kWh Isuzu 6BG1-TQV
- G3 — 70 kWh Detroit D4-7 1

The current fuel system at the plant, which provides the fuel to the run the generators, has the following deficiencies that need to be addressed:

- Indoor Piping – The current piping is no longer compliant with NTPC Piping and Valve Specifications and certain GNWT requirements.
- Outdoor Piping - The current piping is not protected from vehicle damage and is at risk of damage in winter by snow removal equipment.
- Tank level control system - No longer meets current NTPC standards. The fuel tank at the plant is at risk of overflowing, leading to a spill.
- Fuel pump controls - No longer meets the code requirements of the Fire Marshal.
- Fuel pumps – Is not capable of meeting the fuel demand of the plant following the most recent generator (G1) replacement.
- Fuel cooling and filtration – The current system lacks adequate return fuel cooling and fuel filtration. It is not compliant with current NTPC best practice design, it inhibits the efficiency of the engines, and increases the time required for unplanned maintenance.
- Plant configuration - The current fuel system setup restricts access to the G1 genset due to limited space within the plant, making maintenance more difficult to complete

The Corporation monitors regulatory requirements and incorporates these requirements into the 5 year Capital Program. This program replaces/upgrades assets as required to ensure NTPC meets existing regulatory codes. In addition, the Capital Program is updated as regulatory changes occur, ensuring the Corporation continues to meet regulatory requirements.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The current fuel system at the plant is not compliant with certain NTPC corporate policies and regulatory codes, and doing nothing is not a viable option. A failure to upgrade the current fuel system would pose unacceptable safety, reliability, and environmental risks.



Option 2: Fuel System Upgrade

Estimated Costs: \$477,000

This option consists of upgrading the current fuel system at the Jean Marie plant. This project is part of a corporate initiative to upgrade the fuel tanks, piping, and related systems at diesel based plants. These upgrades will enhance plant safety, reliability and ensure compliance with current regulatory requirements. Consistent with this policy, in 2015 a new power plant fuel supply design was completed for the Jean Marie River plant. It consists of the following elements:

- Indoor Piping Upgrade - Fuel piping and valves upgraded to meet current NTPC piping and valve specifications.
- New Fuel System – This includes a new double-walled day tank, a new tank level control system, pumping system, water separator, fuel cooler and filters.
- Fuel tank housing - Fuel tank to be housed in a new separate module beside the plant
- Outdoor Piping Upgrade - Outdoor piping to be integrated into new fuel tank housing and the installation of bollards (posts) to obstruct potential vehicle traffic (snow clearing) near outdoor fuel pipes, thereby reducing risk of damage to the outdoor pipes.

By upgrading the current fuel system at the plant, the Corporation will reduce risk in a number of key areas, particularly fuel spills and the associated consequences. Please see below:

- Environmental - Fuel spills could cause damage to the environment and are costly to remediate.
- Safety
 - Employees - In the event of a fuel spill, staff could be exposed to dangerous fumes or have their skin exposed to the liquid and suffer injury. This risk would exist not only at the initial time of the spill but also throughout the time of the required cleanup.
 - Plant – A fuel spill along with a source of ignition could result in a fire. This could cause significant damage to the plant and potentially significant injuries to staff.
- Reliability
 - Fuel spills – A fuel spill could result in plant shutdown to clean the spill or if a fire were to occur, damage the plant so extensively to make it no longer operational
 - Reduced downtime – The new fuel cooling and filtration system will reduce the time to complete unplanned maintenance on the fuel system. Also, the separate fuel housing makes accessing generators easier, reducing time to complete repairs.



COST ESTIMATES

Table 1 – Budget Estimates

Description	2015/16
Payroll Regular	60,000
Payroll Overtime	25,000
Payroll Fringe Benefits	20,000
Contractors Lump Sum	235,000
Transportation	3,000
Accommodation	6,000
Meals	1,000
Freight	2,000
Engines	1,000
Contingency	37,000
Total Base Project Estimate	\$390,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2015/16	\$390,000	\$0	\$87,000	\$477,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.477M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.073%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
Jean Marie Fuel System Upgrade

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$477	\$596	\$716	\$954
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$19	\$24	\$29	\$39
Return on Ratebase (\$000)	\$23	\$29	\$35	\$46
Sub-Total: Revenue Requirement Increase (\$000)	\$43	\$53	\$64	\$85
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$43	\$53	\$64	\$85
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.073%	0.091%	0.109%	0.146%

SUMMARY OF BUSINESS CASE RATIONALE

The current fuel system at the Jean Marie River plant is not compliant with certain NTPC corporate policies and regulatory codes. The current system poses unacceptable safety, reliability, and environmental risks.

As part of an overall program at NTPC to upgrade the fuel tanks, piping, and related systems at diesel based plants, the Corporation proposes to address these concerns with the installation and commissioning of a new fuel system at the Jean Marie River plant. The benefits realized by making these upgrades at the plant include reduced risk of fuel spills and the associated environmental and safety concerns, as well as reduced plant downtime. The new fuel cooling and filtration system will increase genset efficiency and be in line with current NTPC best practice and regulatory codes.

RECOMMENDATION

The Corporation recommends proceeding with the project as outlined in option 2. Upgrading the fuel system at the plant will allow NTPC to meet its obligation to provide safe, reliable power to customers in an environmentally responsible manner. The total costs to complete the project are estimated to be \$0.477M.



Northwest Territories Power Corporation
Business Case
Jean Marie Fuel System Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page #4.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Selection and Installation of a Lone Worker System

NEED FOR PROJECT

The Corporation is proposing to undertake a project to implement a new Lone Worker System. This system will be a standardized man down alarm system for use at NTPC's generation plants that serves to protect the safety of employees who are working in lone situations.

NTPC takes the safety and security of its employees seriously. This project was undertaken to improve worker safety. The existing system includes both electronic and manual procedures. A review of the existing system revealed areas for improvement, and that there have been incidents where a breakdown in the manual procedures occurred. The Corporation's review identified the following issues:

- Twenty percent of NTPC's current plants do not have an operational electronic man down system as of Sept. 11, 2012, and make use of a manual process
- Among the 80% of plants that do have an operational electronic man down system, the following issues have been observed:
 - o The alarm notification was deemed not quick enough to allow for a rapid deployment of assistance in an emergency situations
 - o No instant alarm notification in place
 - o No tilt based alarm or personal device activated alarm in place
 - o Existing systems are not standardized requiring different training and instruction material to be maintained
 - o Phone line requirement for most of the current systems

Following a structured model for systems deployment, NTPC would undertake the selection and installation of a standardized man down alarm system for use at all of NTPC's generation plants. This would improve worker safety and enable NTPC to continue to comply with current legislation.

The new Lone Worker System is in alignment with NTPC's strategic goal to realize zero injuries through superior safety performance and practices. In an effort to achieve this goal, the Corporation has fostered a corporate culture that focuses on safety, with each employee taking direct responsibility to ensure a safe work environment. The new Lone Worker System is an essential tool necessary for ensuring the safety of employees at remote locations, and it is vital safety component supporting the Corporation's efforts to achieve zero lost time injuries.

BACKGROUND

NTPC is the primary supplier of electrical power in 26 communities within the Northwest Territories. The majority of these locations have power plants that are maintained daily by a Plant Operator who works independently. NTPC Operations, Engineering, IT, and other technical staff also frequently complete work at these locations in a lone worker capacity.

NTPC operates under the NWT Safety Act, which was used as a guide to help establish lone worker requirements and solutions. NWT General Safety Regulations #14 states: "Where a



Northwest Territories Power Corporation
Business Case
Selection and Installation of a Lone Worker System

worker is employed under conditions where he or she, if injured, might not be able to secure assistance, the employer shall provide a means of checking the well-being of that worker at intervals that, under the circumstances, provide adequate protection.”

NTPC plants currently have a mixture of lone worker electronic based systems in place. Each of these has different operating instructions and knowledge requirements for use. In some instances where the lone worker systems have been installed they have been deemed to be no longer operational. For those not operational or where a lone worker system has not been installed, a manual procedure has been put in place to address the lone worker risk. The manual process involves lone workers submitting a form via fax to the Central Control Room (CCR) indicating location, work to be conducted, expected entry and exit time from the plant. The CCR operator monitors the notification and contact authorities if response cannot be received by a lone worker.

The current systems pose a safety risk to employees working in a lone worker capacity who face an emergency. NTPC has recognized the risk and deems it important to have a reliable, user friendly and standardized solution in place to better enhance the safety of its employees and be able to respond to situations that require immediate attention. NTPC’s Operations and Health and Safety Department generated the following list of requirements for a new Lone worker system:

Specific requirements:

- Lone worker system must allow for one way alarm communication to a centralized monitoring system.
- Lone worker system must not hinder work completed by lone worker to a degree determined significant.
- Lone worker device should have push button functionality that would send an instant alarm that help is required.
- Lone worker device should be able to detect problem without operator involvement and send a message that help is required.
- Total time between alarm activation and notification shall be under 5 minutes.
- System should be fully functional inside the primary power plant building.
- Monitoring capabilities required within the Central Control Room (CCR) that indicate plant location where alarm initiated.
- Lone worker system must operate with over 99% availability.
- Local authorities must be contacted to respond to alarm situation.

Secondary requirements:

- Instant alarm notification to local authorities.
- Device operates with two way communication functionality.
- Device functionality within plant compound and all plant buildings.
- Device functionality within the entire community.
- GPS coordinates of device.



Northwest Territories Power Corporation
Business Case
Selection and Installation of a Lone Worker System

ANALYSIS OF OPTIONS

Option 1: Do Nothing

This option would result in NTPC continuing to operate as it does today. In many plants where either electronic man down systems are not installed or are not operational, this would result in continued use of a paper based manual process. In other plants, varying electronic based systems that do not meet some of the regulatory and operational requirements would be used.

This option is inconsistent with the Corporation's values, and strategic priorities of enhancing employee safety. It will not address the needed improvements to the current lone worker systems and is not a viable option.

Option 2: Repair Existing Lone Worker System

Estimated Cost: \$269,000

Each location that currently has an inoperable lone worker system installed could be visited and repairs completed on the system. In locations where no lone worker system is installed, new installations can be completed.

While this would ensure that all sites had an operational lone worker system, many of the requirements identified by the Operations and Safety Departments at NTPC would be unfulfilled. In addition, there would be a lack of standardization. As mentioned previously, there are a number of different systems at the plant sites. This would require significant training, support costs, and monthly costs incurred through independent phone line requirements.



Northwest Territories Power Corporation
Business Case
Selection and Installation of a Lone Worker System

Option 3: Install a Standardized Electronic Lone Worker System in all NTPC Plants**Estimated Cost: \$839,000**

As a separate project, NTPC's IT department will be completing a network consolidation project that will increase internet/WAN reliability to over 99.99% as well as capacity of the channels and installation of wireless (Wi-Fi) communication.

With these upgrades to the network comes an opportunity for use of a lone worker solution that can run on the network and utilize Wi-Fi communications. Wi-Fi based lone worker devices exist that allow for two way communications from personal alarm pendant devices to a centralized alarm and response management system. The solution would be rolled out in an orderly and staged manner at all Plant locations using current NTPC procedures.

The IT department has identified a suitable Wi-Fi based lone worker system that will meet all of the primary requirements and most of the secondary requirements identified by the Operations and Health and Safety Departments. Please see below for key features of the system and its benefits.

- Pendant devices
 - Feature tilt based alarms as well as panic buttons that are worn on lone workers.
 - Have a screen that allows for touchscreen communications and visual receipt of text based information from response system/personnel.
 - Alarm notification and response from/to pendant is immediate.
- Integrated alarm and response management system
 - Allows for central monitoring and response that can be integrated into SCADA HMI (human machine interface). The system allows for multi contact alarm notification and can use a combination of text, email, and voice (phone) notifications.
 - Various alarm types (e.g. amber, red alarm, timed alarm, man down).
 - Two way text/alarm communications occurs between management system and pendant devices.
 - Optional features
 - Online map systems or inputted CAD building drawings can be integrated with the system
 - Use of pendant location based tracking can be implemented



Northwest Territories Power Corporation
Business Case
Selection and Installation of a Lone Worker System

COST ESTIMATES

Table 1 – Budget Estimates

Description	2013/14	2014/15	2015/16
Payroll Regular	-	66,000	64,000
Payroll OT	-	22,000	30,000
Payroll Fringe	-	21,000	20,000
Consultant Lump Sum	-	20,000	5,000
Contractors Lump Sum	-	1,000	-
Transportation	-	12,500	20,000
Accommodation	-	5,500	8,000
Meals	-	3,000	4,000
Construction Camp	-	9,500	10,000
Permits	-	1,500	-
Office Furniture	-	3,000	-
Communication Equipment	23,000	133,000	175,000
Total Base Project Estimate	\$23,000	\$298,000	\$336,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$23,000	\$1,000	\$5,000	\$29,000
2014/15	\$298,000	\$12,000	\$66,000	\$376,000
2015/16	\$336,000	\$24,000	\$74,000	\$434,000
Total				\$839,000

Along with the cost of the implementing the new lone worker system, there is ongoing maintenance and support costs of \$150,000 annually.



Northwest Territories Power Corporation
Business Case
Selection and Installation of a Lone Worker System

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 15 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.839M
- Additional O&M costs of \$0.150M per year
- Amortization rate of 6.52%
- Return on Ratebase of 6.88%
- Allocation of costs to entire region

Given the above assumptions, the average rate impact of the project for NTPC's customers is estimated at 0.248%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$839	\$1,049	\$1,259	\$1,678
Amortization Period (Approx. Year)	15	15	15	15
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
O&M Expense (\$000)	\$150	\$150	\$150	\$150
Amortization Expense (\$000)	\$55	\$68	\$82	\$109
Return on Ratebase (\$000)	\$58	\$72	\$87	\$115
Sub-Total: Revenue Requirement Increase (\$000)	\$262	\$291	\$319	\$375
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$262	\$291	\$319	\$375
Total Revenue Requirement All Zones (\$000)	\$105,840	\$105,840	\$105,840	\$105,840
Average % Rate Increase	0.248%	0.275%	0.301%	0.354%



Northwest Territories Power Corporation
Business Case
Selection and Installation of a Lone Worker System

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation reviewed the existing lone worker system and found the current system needed to be improved and required replacement. The operations and health and safety departments of NTPC have identified specific requirements of a new system. This new system design complies with current legislation and maintains operational effectiveness. In addition, the new system is a vital safety component supporting the Corporation's efforts to achieve its strategic goal of zero lost time injuries.

The IT department has identified a Wi-Fi based technology solution that will provide significant improvement in the capabilities of the loner worker system. With the network upgrade taking place at the plants, it is now possible to utilize such a system.

The new system will allow employees to communicate to a response management team from a personal alarm pendant device in the event it is needed. The communications will be instant, giving lone working employees greater security compared to the current systems in place. This new system will significantly improve the safety and security of employees when they are working alone.

RECOMMENDATION

NTPC strives to foster a strong safety corporate culture that sets workplace safety as a top priority, with a strategic goal of zero lost time injuries. In order to further this commitment and protect those employees who are working in a lone worker situation within its power generation facilities, it is recommended that NTPC pursue option 3. The total project costs to install the new Wi-Fi based Lone Worker system is estimated at \$0.839M, with an annual operating and maintenance costs of \$0.150M.



Northwest Territories Power Corporation
Business Case
Selection and Installation of a Lone Worker System

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page #6.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Norman Wells – Plant Heating Conversion

NEED FOR PROJECT

The Corporation is proposing to undertake a project to install a new NTPC standard 90,000L storage tank in Norman Wells. Imperial Oil periodically temporarily shuts off their natural gas supply to the community when the company undertakes plant shutdowns for maintenance and power interruptions. As a result, NTPC's Norman Wells power plant comes online and provides the power requirements of the community, utilizing its main diesel storage tank. This plant has an existing 4000L backup diesel storage tank that is currently being utilized to provide fuel to the diesel gensets. The current capacity of this storage tank becomes an issue when the plant is required to operate for extended periods of time.

BACKGROUND

The power plant in Norman Wells provides standby power to the community. Imperial Oil provides the primary source of power and is purchased by NTPC and distributed to the community.

Imperial Oil provides the community with natural gas as a heating source and NTPC uses the natural gas to provide plant heating and engine block heating through natural gas boilers and hydronic heating systems. Imperial Oil advised NTPC and the community of Norman Wells in October 2013 that the gas supply for heating would be shut off to the community and all commercial customers.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The option of “do nothing” will leave the backup power plant at risk of freezing up in the winter and not being able to provide the heating requirements of keeping the backup diesel gensets in a ready to go online state. This would put the community at risk of NTPC of not being able to meet the power requirements when Imperial Oil is unable to provide power.

Option 2: 90,000L Storage Tank

Option 2 consists of installing a new NTPC standard 90,000L storage tank, reuse of the existing 4,000L storage tank, and replacement of the existing natural gas boilers and hydronic heating system with the diesel fired boilers and hydronic heating systems. The new 90,000L double walled storage tank will be used for supplying the diesel fuel requirements for the diesel gensets. The existing 4,000L storage tank will be utilized for storage and supply of diesel fuel for the new diesel fired boilers and hydronic heating systems. The capital cost of this option is estimated at \$0.410M.

The benefits of this option are summarized as follows:

- Eliminates the risk of plant freeze up by ensuring that the backup plant is in a ready online state 24/7.
- Ensures that NTPC is able to meet the power requirements of the community for extended periods of time in the event of Imperial Oil plant shutdowns.



Northwest Territories Power Corporation
Business Case
Norman Wells – Plant Heating Conversion

Option 3: Install Weights & Metering Devices to Current Storage System

This option consists of utilizing the existing diesel fuel storage system and installing two weights and measures approved diesel fuel metering devices so consumption for the diesel gensets and diesel fired boilers can be recorded separately. In addition, this option requires the removal of the existing natural gas boilers and replacing them with diesel fired boilers and a hydronic heating system. This is the least costly option estimated at \$0.275M.

COSTS ESTIMATES

Table 1 – Budget Estimates

Budget Estimates

Description	2013/14	2014/15
Payroll Regular	21,000	13,000
Payroll OT	1,000	5,000
Payroll Casual	0	7,000
Payroll Fringe	8,000	6,000
Consultants Lump Sum	12,000	0
Contractors Lump Sum	15,000	52,000
Transportation	3,000	0
Accommodation	500	0
Meals	400	0
Construction Camp	500	0
Freight	14,500	11,000
Heating Systems	46,000	31,000
Fuel Storage Tanks	78,000	500
Total	\$199,900	\$ 125,500



Northwest Territories Power Corporation
Business Case
Norman Wells – Plant Heating Conversion

Project Estimated Cost:

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$199,900	\$6,500	\$33,600	\$240,000
2014/15	\$125,500	\$7,000	\$37,500	\$170,000
Total				\$410,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates.

The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.41M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.06%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
Norman Wells – Plant Heating Conversion

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$410	\$513	\$615	\$820
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$17	\$21	\$25	\$33
Return on Ratebase (\$000)	\$20	\$25	\$30	\$40
Sub-Total: Revenue Requirement Increase (\$000)	\$37	\$46	\$55	\$73
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$37	\$46	\$55	\$73
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.06%	0.08%	0.09%	0.13%

SUMMARY OF BUSINESS CASE RATIONALE

The installation of a 90,000L tank will allow NTPC to meet the power needs of the community for extended periods when Imperial Oil shuts down its plant for repairs and maintenance. Without the new storage tank, the community of Norman Wells would be without power, which thereby necessitates an immediate commencement of the project to ensure no extended power outages occur. In addition, the installation of the new tank will allow the Corporation to meet the PUB requirement to account for generation/production fuel costs and heating fuel costs separately.

RECOMMENDATION

The Corporation recommends proceeding with option 2, as it provides the least amount of risk to the community of Norman Wells, with adequate storage of both production/generation fuel and heating fuel storage that will meet the power generation needs of the town. Total project costs to complete the project are estimated at \$0.410M.



Northwest Territories Power Corporation
Business Case
Norman Wells – Plant Heating Conversion

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis Of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis shown on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Snare Cascades Spillway Repairs

NEED FOR PROJECT

NTPC is proposing to undertake a project to repair the labyrinth spillway located at the Snare Cascades hydroelectric plant. A spillway is a structure used to provide the controlled release of flows from a dam or levee into a downstream area. Water does not normally flow over a spillway and it is typically used during flood periods. Spillways release floods so that the water does not overtop and damage or destroy the dam.

The labyrinth spillway has been damaged due to water erosion that arises when discharges from the upstream plants are greater than the design capacity of the Snare Cascades plant. Years of erosion have caused significant damage to the structure with a number of inspection reports observing erosion of the concrete including cracks, eroded areas and some exposure of rebar.

In 2012, a small trial was conducted with two sections of concrete product placed over the spillway. The product has been in place for over three years and is holding up well. Given the success of the trial, NTPC proposes expanding its use of the product to repair the rest of spillway.

BACKGROUND

The Snare Cascades Development was commissioned in 1996 and is owned by the Dogrib Power Corporation and operated by NTPC. The Cascades is the third plant in the Snare Hydro system and is located 3 km downstream of Snare Falls. It is the most recent facility on the Snare run-of-river system.

The overall development consists of a concrete labyrinth spillway with a crest level at an elevation of 182.88 m, an approach channel and a powerhouse. When discharges from the upstream plants are greater than the design capacity of the unit, the water flows pass over the top of the labyrinth spillway.

The Spillway is intact but the concrete is crumbling. Inspection reports indicate evidence of cracks, eroded areas, and rebar exposure. As part of maintaining the safety of the dam and keeping it in good working order, repair of the spillway is required.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

While there is no immediate danger, the condition of the spillway puts the safety of the dam at risk. Failure to make repairs will result in continued damage to the spillway. The spillway is a vital component of the dam and its safe and effective operation, making option one not viable.



Northwest Territories Power Corporation
Business Case
Snare Cascades Spillway Repairs

Option 2: Complete Spillway

Estimated Costs: \$700,000

This project involves resurfacing the labyrinth spillway. The benefits of option 2 are that it reduces risks in the following areas:

- Reliability – repair of the spillway will enhance safety of the dam and enable it to continue to operate effectively
- Environmental – the spillway controls the release of water in flood situations. Unrepaired, it will sustain more damage over time with the risk of significant amounts of water being released in an uncontrolled way, with potentially significant negative environmental consequences.
- Financial – if the spillway is not repaired, it may deteriorate to the point where it requires complete replacement. Such a replacement would involve a multi-million dollar capital investment.

COST ESTIMATES

Table 1 – Budget Estimates

Description	2015/16
Payroll Regular	\$34,000
Payroll OT	\$30,000
Fringe Benefits	\$12,000
Consultants Lump Sum	\$6,000
Contractors Lump Sum	\$418,000
Transportation	\$12,000
Accommodation	\$1,000
Meals	\$500
Equipment Rental	\$45,000
Freight	\$15,000
Total Base Project Estimate	\$573,500

Project Cost Estimates

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2015/16	\$573,500	-	\$126,500	\$700,000
Total				\$700,000



Northwest Territories Power Corporation
Business Case
Snare Cascades Spillway Repairs

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 60 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.700 M.
- Amortization rate of 1.67%.
- Return on Ratebase of 7.18%.
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.167%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$700	\$875	\$1,050	\$1,400
Amortization Period (Approx. Year)	60	60	60	60
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$12	\$15	\$18	\$23
Return on Ratebase (\$000)	\$50	\$63	\$75	\$101
Sub-Total: Revenue Requirement Increase (\$000)	\$62	\$77	\$93	\$124
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$62	\$77	\$93	\$124
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.167%	0.208%	0.250%	0.333%



Northwest Territories Power Corporation
Business Case
Snare Cascades Spillway Repairs

SUMMARY OF BUSINESS CASE RATIONALE

Over the years, the labyrinth spillway has been damaged due to water erosion that arises when discharges from the upstream plants are greater than the design capacity of the Snare Cascades plant. The spillway will continue to deteriorate until action is taken to correct the problem. This poses significant risks to the safety of the dam.

If the problem is not addressed, the dam may cease operation. There is also a substantial environment risk. If the spillway does not function properly, it would not allow a controlled release of water in a flood situation. This could mean that significant amounts of water may be released in an uncontrolled way with potentially significant environmental consequences.

There are also substantial financial risks to inaction. The spillway is a critical component of the dam. If it is not repaired, it may deteriorate to the point where it must be replaced at a much greater capital cost (multi-million dollar investment).

RECOMMENDATION

It is recommended the Corporation proceed with the project as outlined in option 2. The total cost to complete the project is estimated at \$0.700M.



Northwest Territories Power Corporation
Business Case
Snare Cascades Spillway Repairs

Attachment A
Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

NTPC is proposing to undertake a project to correct deficiencies identified in the 2011 Dam Safety Review (DSR) related to Spillway 5B that connects to the Snare River system. The DSR Report identified that freeze/thaw conditions have caused damage to the secondary concrete that support the gains. It also identified some minor undercutting/erosion of the buttress toe at Bays 3, 4 and 5. As a result, the Corporation will need to undertake improvements to the secondary concrete that supports the Bay 3 and 4 heated gains, repair undercutting/erosion of the buttress toe at Bays 3, 4 and 5, as well as repair seepage monitoring and brushing.

BACKGROUND

Spillway 5B is located at the end of an arm off the southern end of Big Spruce Reservoir. The spillway is a stop log controlled reinforced concrete structure comprising six bays each 6 m (wide) x 2.5 m (deep) and two bays each 6 m x 5.8 m and is founded on fresh, widely jointed diorite and granite of good to excellent quality. Along the upstream right side, a structurally independent retaining wall leads upstream from the right abutment and retains the fill from Side Dam 5B. Along the downstream right side, a timber crib retaining wall retains these same fills and supports an enclosure.

Water released from Spillway 5B returns to the Snare River via a 13 km long waterway, including two small lakes, rejoining the main channel 7.5 km downstream of Snare Rapids and 8 km above Snare Falls. Access to the site is via boat during the summer, snowmobile during winter or helicopter as appropriate.

Stop logs are lifted by an electrically powered gantry crane with power supplied via a 6.9 kV tie line from Snare Rapids. Back-up power is via a gasoline powered generator. The spillway can only be operated locally and equipment has generally performed satisfactorily. Most of the logs are removed and reinstalled during each year's normal operating cycle. Bad weather could present access problems and operations could be delayed.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

A previous DSR completed in 2000 identified cracking in the second stage concrete around the heated gains. The concrete has further deteriorated since that time and it appears that the concrete between the cracks and the gains has the potential to fall off in long vertical strips. If this happens, the gains might twist under stop log loading, potentially jamming a stop log and thus inhibit or prevent stop log removal. The "do nothing" option is not considered a viable option as the deficiency is considered a dam safety concern and requires repair as soon as possible.



Northwest Territories Power Corporation
Business Case
Spillway 5B Improvements

Option 2: Various Improvements to the 5B Spillway

Estimated Costs: \$440,000

This option entails repairing the deficiencies identified in the 2011 DSR. These issues are as follows:

- 1) Improvements to the secondary concrete that support the Bay 3 and 4 heated gains.
- 2) Repair undercutting/erosion of the buttress toe at Bays 3, 4 and 5.
- 3) Repair seepage monitoring.
- 4) Brushing along the dam.

This option will repair spillway 5B thereby correcting the present safety issues and reducing potential stop log jamming/log removal problems.

COST ESTIMATE

Table 1 – Budget Estimates

Description	2013/14	2014/15	2015/16
Payroll Regular	1,000	-	21,000
Payroll O/T - CWIP	-	-	16,500
Fringe Benefits	1,000	-	7,000
Consultants Lump Sum	10,000	8,000	6,000
Contractors Lump Sum	-	-	219,000
Transportation	5,000	-	12,000
Accommodation	-	-	1,000
Equipment Rental	-	-	39,000
Freight – other	-	-	6,000
Total	\$17,000	\$8,000	\$327,500

Project Estimated Costs

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$17,000	\$2,000	\$9,000	\$28,000
2014/15	\$8,000	\$2,000	\$2,000	\$12,000
2015/16	\$327,500	\$1,000	\$71,500	\$400,000
Total				\$440,000



Northwest Territories Power Corporation
Business Case
Spillway 5B Improvements

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 60 years at the currently approved GRA amortization rates.

The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.440M.
- Amortization rate of 1.67%.
- Return on Ratebase of 7.18%.
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.105%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$440	\$550	\$660	\$880
Amortization Period (Approx. Year)	60	60	60	60
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$7	\$9	\$11	\$15
Return on Ratebase (\$000)	\$32	\$39	\$47	\$63
Sub-Total: Revenue Requirement Increase (\$000)	\$39	\$49	\$58	\$78
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$39	\$49	\$58	\$78
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.105%	0.131%	0.157%	0.210%



SUMMARY OF BUSINESS CASE RATIONALE

The 2011 DSR identified a number of deficiencies related to the Spillway 5B situated near the Big Spruce Reservoir. NTPC will need to undertake spillway repairs to correct safety concerns and prevent stoplog removal issues. The project is urgent in nature given the safety concerns and potential risk to personnel operating the spillway.

RECOMMENDATION

It is recommended that NTPC proceed with option 2. This option addresses all the deficiencies identified in the 2011 DSR and eliminates the present safety concerns. Total capital costs to complete the project are estimated at \$0.440M.



Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections.</i>
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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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>

2016/17 Business Cases



Northwest Territories Power Corporation
Business Case
Aklavik Variable Speed Generator

NEED FOR PROJECT

NTPC is proposing to install a variable speed generator as a pilot project to reduce diesel consumption in Aklavik. The variable speed generation unit selected has been successfully used in other markets. It is currently the only unit of this type that will match with the generation needs at the Aklavik power plant. The variable speed genset also has the capability to manage renewable technology add-ins such as solar or wind technologies. The yearly average load is 388 kW with an average diesel fuel consumption of 900,000 liters per year and an overall average efficiency of 3.54 kWh/L.

The new technology variable speed unit has a greater fuel efficiency of 3.9kWh/L which will displace over 80,000 liters of diesel fuel per year with an estimated savings of approximately \$99,000/year based on a forecasted diesel price of \$1.23 per litre. The variable speed unit has been priced to include the first year maintenance costs supplied by the OEM to ensure reliability of the new technology which will offset the first year maintenance costs of approximately \$350K.

Background

The proposal from Collicutt Energy includes a 600kW variable speed genset configured in an outdoor containerized module unit. The proposal included in this package comes with a 12 month fuel efficiency performance guarantee and a three step progress payment schedule with the final payment due upon the commissioning of the asset. If the efficiency performance guarantee is not met the vendor will purchase back the unit within the first year, charging NTPC a \$0.12/kWh generated or a minimum charge of 150,000kW per month. This would amount to an NTPC cost of between \$220K and \$350K depending on usage if the unit proved to be less efficient than committed. There exists a suitable location for the new unit at the power plant where it can easily be connected to both the fuel supply and an independent 600V breaker at the supply buss.

The technology behind the variable speed genset is that its speed is uncoupled from the standard 1800RPM units that provide power at a frequency of 60Hz with varying loads. The variable speed genset is not linked to frequency and can vary its speed down to very low RPM's for low loads and increase its speed as the load increases. The variable speed genset has a DC generator versus an AC generator in a standard 1800RPM unit that takes the DC power, rectifies it, and inverts it to AC current supply matching what is supplied by the standard units. These lower RPM's increase fuel efficiency and decrease the maintenance based on the fact that it will be running at lower RPM's on average and will have less wear and tear on components with the lower RPMs. The power plant in Aklavik is accessible by winter road and is a short plane ride from Inuvik, the major center servicing this community.



ANALYSIS OF OPTIONS

Option 1: Do Nothing

The "do nothing" approach will not facilitate any attempts to increase the efficiency at the power plant in Aklavik, have any anticipated GHG emissions reductions, nor allow for the pilot of variable speed generation technology in an isolated community.

Option 2: Purchase and installation of a Variable Speed Generator

This project will include the purchase and installation of a variable speed 600kW genset packaged in a containerized unit for the community of Aklavik. The unit will be supplied with external connections for both the high voltage cabling and fuel supply and return. The output power for the unit will be tied into an existing 600V breaker on the buss inside the power plant. There will also be 120V power and communication cables run for the existing plant to the containerized unit. The unit will be connected to NTPC's existing SCADA system for remote monitoring for performance, troubleshooting and data history. It is expected that this unit will be shipped to Aklavik by late summer sealift and be connected and commissioned before the end of fall.

Option 2 will provide lower operational costs with diesel fuel being the largest expense at the power plant. Reliability will not be compromised at the power plant to test the pilot project as the existing genset lineup will stay in the power plant during this pilot. The project will offset maintenance costs to existing units. The vendor will also cover all first year maintenance costs, further reducing the risk of managing newer technology in a remote location. This is the only known vendor able to supply this type of technology and willing to provide guaranteed performance and fuel efficiency savings.



Northwest Territories Power Corporation
Business Case
Aklavik Variable Speed Generator

Table 1 – Projected Fuel Savings

Typical Generation	3,190,990
Conventional Generation	
Total Diesel (l)	901,142
Diesel 1 Run Time (hrs)	8,760
Diesel 1 Average Load (kW)	254
Diesel 2 Run Time (hrs)	7,193
Diesel 2 Average Load (kW)	134
Diesel 3 Run Time (hrs)	
Diesel 3 Average Load (kW)	
Efficiency	3.54
Variable Speed Generation	
Total Diesel (l)	820,574
VSG Diesel (l)	706,627
Other Diesel (l)	113,947
Diesel Run Time (hrs)	1,622
Diesel Average Load (kW)	253
VSG Run Time (hrs)	7,193
VSG Average Load (kW)	387
Efficiency	3.89
Diesel Displaced (l)	80,568
% Diesel Used	91%
	\$ 1.23
Total Estimated Fuel Savings	\$99,098.64

The vendor provision of first year maintenance costs was not included in these calculations. Future incremental maintenance costs of adding the new pilot unit will be offset by maintenance savings (substantial decrease in hours) on other units. If the unit proves reliable and suitable there is a possibility to remove a unit at a future date. That opportunity is not included in the rate or cost calculations.



COST ESTIMATES

Table 2 – Project Budget Estimates

Description	2016/17
NTPC Payroll	\$ 80,000
Consultants Lump Sum	\$ 30,000
Contractors Lump Sum	\$ 80,000
Expenses (travel etc)	\$ 30,000
Freight	\$ 20,000
Modular 600kW Variable Speed Genset	\$ 950,000
Equipment Rental	\$ 2,000
Mechanical Materials	\$ 5,000
Electrical Materials	\$ 7,000
Foundation	\$ 5,000
Residual Heating Materials	\$ 5,000
Total Direct	\$ 1,209,000
Contingency	\$ 70,000
Overheads	\$ 145,000
IDC	\$ 25,000
Total	\$ 1,449,000

Fuel savings are captured as annual O&M savings in the sensitivity analysis in Table 3. The project would have an estimated payback of approximately 14 years accounting for the project costs and fuel savings.



Northwest Territories Power Corporation
Business Case
Aklavik Variable Speed Generator

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on Ratebase over time. The amortization period of the project is approximately 29 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$1.449M.
- Amortization rate of 3.44%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.037%. The sensitivity analysis in Table 3 shows the rate impacts of various cost scenarios. First year rate impacts are slightly positive with returns expected as the return on Ratebase decreases over time.

Table 3– Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$1,449	\$1,811	\$2,174	\$2,898
Amortization Period (Approx. Year)	29	29	29	29
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$50	\$62	\$75	\$100
Return on Ratebase (\$000)	\$71	\$88	\$106	\$141
Sub-Total: Revenue Requirement Increase (\$000)	\$120	\$151	\$181	\$241
Less: Estimated O&M Savings (\$000)	\$99	\$99	\$99	\$99
Total Revenue Requirement Impact (\$000)	\$21	\$52	\$82	\$142
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.037%	0.088%	0.140%	0.243%



SUMMARY OF BUSINESS CASE RATIONALE

Variable speed generation will help minimize the cost of providing the most fuel efficient solution to communities that will indefinitely rely on diesel as their primary source of generation. The technology is tested and readily available but is new to our organization and our unique challenging environments. There is therefore some value, in piloting this technology. It is also suitable for the range of units available in terms of matching load requirements. Further to this the over 80,000 litres of displaced fuel has additional benefits in reducing emissions and greenhouse gas emissions.

RECOMMENDATION

The Corporation recommends option 2 the purchase and installation of a variable speed genset. This unit will increase fuel efficiency performance and reduce maintenance costs at the power plant in Aklavik. The total costs to complete the project are estimated to be \$1.449M.



Northwest Territories Power Corporation
Business Case
Aklavik Variable Speed Generator

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis Of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page #5.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options and Background section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures. Risks are also discussed in the Analysis of Options section of the business case.</i>



NEED FOR PROJECT / BACKGROUND

NTPC is proposing to undertake a project to rebuild a section of the distribution line (feeder 7) that begins at the Pine Point substation and ends at a transformer that steps up the voltage to a transmission line that connects to Fort Resolution. The poles and cross arms have reached the end of their useful life and are in need of replacement. Specifically, the section of feeder 7 that is in need of repair is 3.2 km long and is difficult to access due to uneven terrain and gulleys. The costs associated with maintaining these structures are high due to the difficulty accessing the area given the nature of the terrain. This section of the distribution line power line section will be moved to the side of an existing roadway to allow easier access and reduce maintenance costs.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option is not a viable option as it will result in ongoing outages due to structure failures. Given the structures are near end of life, the outage frequency is expected to increase if the status quo continues. Additional costs will be incurred to complete repairs that arise from the outages. Significant maintenance costs will continue to be incurred to maintain the transmission line.

Option 2: Install New 3.2 km Distribution Line Estimated Cost: \$598,000

This option entails rebuilding a 3.2 km section of the distribution line that connects the Pine Point substation to the transmission line that carries electricity to Fort Resolution. The distribution line will be relocated closer to an existing roadway approximately 100 meters from the present line location. This will entail installing poles, cross arms, conductors and guy wires with anchors for structural stability. The road is government-owned rather than privately owned, making it less difficult to implement the project and obtain the necessary easements. The work will be completed during the annual planned Taltson maintenance outage and there is no separate planned outage required.

The benefits of this option are summarized below:

- Reliability – The project will improve the power line reliability by avoiding structure failures and reduce the number of potential outages and the associated revenue loss.
- Cost savings - Moving the line to the side of the road is expected to reduce operational costs for servicing the line and future tree/vegetation management.

Option 3: Replace Existing Distribution Line Estimated Cost: Not Estimated

The cost to complete this option will be significantly higher than option 2 due to difficulty of access. The terrain is rough and cannot be traversed by trucks and requires the Corporation to rent specialty equipment, which would increase the length of time to complete the project and increase



Northwest Territories Power Corporation
Business Case
Rebuild Section of Distribution Feeder 7

its costs. In addition, a land survey may be required, further escalating cost. Furthermore, ongoing maintenance costs will remain higher than option 2.

COST ESTIMATES

Table 1 – Budget Estimates

Project Design

Description	2016/17
Payroll Regular	102,000
Payroll Overtime	93,000
Payroll Fringe Benefits	36,000
Accommodation	40,000
Meals	23,000
Replacement Poles	147,000
Contingency	66,000
Total	507,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2016/17	\$507,000	\$0	\$91,000	\$598,000
Total Project Cost				\$598,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 39 years at the currently approved GRA amortization rates.

The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.598M.
- Amortization rate of 2.54%.
- Return on Ratebase of 6.88%.
- Allocation costs to Taltson Zone only.



Northwest Territories Power Corporation
Business Case
Rebuild Section of Distribution Feeder 7

Given the above assumptions, the average rate impact of the project for NTPC's Taltson Zone customers is estimated at 0.55%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$598	\$748	\$897	\$1,196
Amortization Period (Approx. Year)	39	39	39	39
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$15	\$19	\$23	\$30
Return on Ratebase (\$000)	\$41	\$51	\$62	\$82
Sub-Total: Revenue Requirement Increase (\$000)	\$56	\$70	\$84	\$113
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$56	\$70	\$84	\$113
Total Community Revenue Requirement (\$000)	\$10,248	\$10,248	\$10,248	\$10,248
Average % Rate Increase	0.550%	0.687%	0.825%	1.099%

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation has identified the need to rebuild the transmission line near the Pine Point substation in Fort Resolution. The poles and structures that constitute feeder 7 have reached the end of their useful lives and have to be replaced. The area where feeder 7 is located is difficult to access and costly to maintain. Rebuilding the transmission line near an existing roadway will significantly reduce the cost of replacing the poles as well as operational costs for servicing the line and carrying out vegetation clearing activities. The project will avoid structural failure and improve power line reliability.

RECOMMENDATION

It is recommended that NTPC proceed with the proposed project as outlined in option 2. The total costs to complete the project are estimated to be \$0.598M.



Northwest Territories Power Corporation
Business Case
Rebuild Section of Distribution Feeder 7

Attachment A

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PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis Of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis shown on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

The Corporation is proposing to complete a project to replace the unsupported and failing automatic meter reading system in Fort Smith. This meter reading system had 12 years of successful operation but now has several issues:

- Recertification - The meters installed now require re-certification to be compliant with Measurement Canada requirements. Recertification of the current meters would be costly and have significant operational issues as they must be brought out of service to be certified.
- Manual meter reading - Degradation in signal quality has resulted in up to 160 manual reads each month
- Technology obsolescence - Meters which work on this technology are no longer available and the supplier no longer supports this technology
- Meter failures - Five percent of total stock so far have failed with significantly more expected to fail in the near term. Of the current inventory, 80% have been in operation for nearly eleven years. Based on feedback from meter manufactures and recertification companies, this particular meter series has been shown to typically fail in the tenth year of operation. Once the 50% threshold is reached with half of the automatic readers no longer functioning properly, running a 50% automated and 50% manual system will become impractical. A mass meter replacement will be required.
- Revenue Losses - As meters fail and customers utilize power, the energy usage is not recognized by the meter, which results in a loss of revenue as the usage is not captured and there is no practical way to assess the customer's energy usage.

BACKGROUND

NTPC installed Hunt Technologies automatic meter reading system in the community of Fort Smith in 2004. This system uses the electrical power lines to carry an electronic signal from the customer's meter to a receiver in the power plant to record energy consumption. This technology allowed NTPC to access meter readings electronically and eliminated the need for comprehensive manual meter reading by the line crew. The age of the meters requires them to now be recertified at considerable cost and the technology has become obsolete and no longer supported by the supplier. The rate of meter failure has been increasing in recent years and is expected to increase given the meters have prematurely reached the end of their useful life.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

Due to Measurement Canada requirements, the revenue meters being used in Fort Smith require re-certification or replacement in the near future. NTPC does not have enough meters in its inventory for a systematic re-certification program. Also, replacement meters that work with this technology are not available. Failing meters and lack of vendor support for the existing technology requires that the existing metering infrastructure be retired and a suitable replacement found.



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Business Case
Fort Smith IMH Metering Upgrade

Given these factors, doing nothing would not correct the issues with the automatic reader system is not a viable option.

Option 2: Replace With Standard Meters
Estimated Costs: \$1,150,000

This option would involve replacing the existing meters with standard meters. The total cost of the project would be approximately \$80,000 in capital costs with an annual meter reading expense of approximately \$100,000 per year. Based on these costs a present value (PV) analysis was completed (Table 1) to estimate the total lifecycle cost of using standard meters.

Table 1 – Project Cost Estimate – Standard Meters

Project Characteristics	Base Estimate
Taltson Zone Return	6.88%
Expected Life New Meters (Years)	20
Manual Meter Reading Cost per Year (\$000)	\$100
PV of Manual Meter Reading Cost (\$000)	\$1,070
Standard Meter Capital Cost (\$000)	\$80
Total Project Cost Estimate (\$000)	\$1,150

The life of the new meters was estimated at 20 years. Using the rate of return in the Taltson zone to discount the annual cost of manual meter reading, the rounded PV amount is \$1.07M. Adding the \$80k capital cost for the standard meters results in a total cost estimate of \$1.15M if this option is selected.

The annual meter reading expense is the main driver of the cost of this option, and is quite substantial as the line crew would have to manually read approximately 1,300 meters and also be responsible for manually disconnecting/reconnecting customers. These substantial meter reading costs were one of the reasons that the current automated meter reading system was implemented.

Option 3: Install Current Generation 2 Way Metering
Estimated Costs: \$653,000

In 2016 NTPC initiated a pilot project in Jean Marie River to evaluate a 2-way metering system called Gridstream RF which is provided by Landis + Gyr. This project is now up and running and operating successfully. Based on the success of this initial project NTPC is proposing to use this new meter technology in Fort Smith.

A brief description of the new 2-way metering system and its key components are listed below:



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Fort Smith IMH Metering Upgrade

- Meters – digital meters which provide remote connect/disconnect/limiting capabilities. Meters transmit an RF (radio frequency) signal to report data.
- Routers - Receive the RF signal and repeat the signal to other routers or the collector.
- Collectors – receive the RF signal and send the data to the database.
- Command Center Software - controls meters, records meter information, reports on individual or grouped meter data and provides alerts on meter and distribution system disruptions.
- SmartWorks Software – provides meter management throughout the Corporation and an external customer portal of account meter readings and energy usage.

Based on the capabilities of the new system as outlined above, the corporation and its customers would realize a number of benefits. They include but are not limited to the following:

Customer Benefits

- Consistently accurate actual, not estimated, usage on power bills.
- Energy consumption information available through portal.
- Can assist customers in demand side management.
- In home electricity monitoring devices are available.
- Better move in/move out experience.
- Beyond the meter devices available to monitor and control household devices.

Customer Service and Billings Benefits

- Accelerates billing process and accelerates payment receipt reducing working capital.
- Better, more informed response to billing inquiries.
- Reduces steps required to process service orders.
- Allows for easier and efficient management of collection process.
- Identifies energy theft and meter tampering.
- Allows for 3rd party value added services such as water meter reading.

Operations Benefits

- Eliminates the time and physical risks of manual reading.
- Local operators are separated from collection disconnect/limiting conflicts.
- Reduces meter access issues.
- Provides accurate graphical display of meter location.
- Reports on self-generation.

Transmission & Distribution Benefits

- Provides detailed information for distribution load management.
- Allows for immediate outage detection and locating.
- Data available and reports produced for power quality / voltage monitoring.
- Facilitates system diagnostics and reporting.

Asset Management and Engineering Benefits

- Assists with community load profiling and forecasting.



Northwest Territories Power Corporation
Business Case
Fort Smith IMH Metering Upgrade

COST ESTIMATES

Table 2 – Budget Estimates

Description	2016/17
Payroll Regular	31,000
Payroll Overtime	19,000
Payroll Fringe Benefits	11,000
Meters	411,000
Computer Software	55,000
Contingency	26,000
Total Base Project Estimate	\$553,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2016/17	\$553,000	\$0	\$100,000	\$653,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 21 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.653M
- Amortization rate of 4.73%
- Return on Ratebase of 6.88%
- Allocation of costs to Taltson Zone

Given the above assumptions, the average rate impact of the project for NTPC's Taltson Zone customers is estimated at 0.740%. The sensitivity analysis in Table 3 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
Fort Smith IMH Metering Upgrade

Table 3 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$653	\$816	\$980	\$1,306
Amortization Period (Approx. Year)	21	21	21	21
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$31	\$39	\$46	\$62
Return on Ratebase (\$000)	\$45	\$56	\$67	\$90
Sub-Total: Revenue Requirement Increase (\$000)	\$76	\$95	\$114	\$152
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$76	\$95	\$114	\$152
Talston Zone Revenue Requirement (\$000)	\$10,248	\$10,248	\$10,248	\$10,248
Average % Rate Increase	0.740%	0.925%	1.110%	1.480%

SUMMARY OF BUSINESS CASE RATIONALE

The current automatic meter reading system in Fort Smith is starting to fail. Approximately 5% of the total units have failed and about 80% have reached a point in their lifecycle where they are also expected to fail. The failure of meters will cause the corporation to lose revenue despite providing power service to customers. This is not sustainable and a mass meter change is required.

NTPC has evaluated a number of options to replace the existing meters. At present, there are no replacement meters, based on the current technology the corporation is using. Also, the supplier no longer supports the technology. Therefore the options that remain are returning to standard meters or implementing a new automated meter system.

In evaluating both of these options, the use of a new automated system is clearly superior. The overall project costs are much lower for the automated system and it will be able to provide a number of benefits to customers and to the corporations' internal processes in a number of areas.



Northwest Territories Power Corporation
Business Case
Fort Smith IMH Metering Upgrade

RECOMMENDATION

The Corporation recommends proceeding with the installation of the Gridstream RF two-way metering system as outlined in option #3. NTPC successfully installed this system in Jean Marie River and will leverage its experience to achieve a similar result in Fort Smith. The total costs to complete the project in Fort Smith are estimated to be \$0.653M.



Northwest Territories Power Corporation
Business Case
Fort Smith IMH Metering Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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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.	<i>The Cost Estimates section addresses Estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page #5.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

The Corporation is proposing to install a load bank at the Pine Point substation for the Taltson Hydro unit. During the winter season, when the load on the system is between 12.3 MW and 13.0 MW, there is a resonant vibration that occurs, which is known as the rough zone. The vibration is quite significant when the system enters this zone of operation.

A load bank is a device that develops an electrical load and applies the load to a power source. It then converts or dissipates the resultant power output of the source. The purpose of adding the load bank would be to add load to the Taltson system when the existing load is between 12.3 MW and 13.0 MW. When the additional load from the load bank is added to the unit, the resulting load would then be above the higher range (13.0 MW) of the rough zone, thus eliminating the vibrations from the unit.

BACKGROUND

The Taltson Hydro unit is an 18 MW unit that was originally installed in 1964. Taltson was originally built to supply power to the Cominco Mine in Pine Point and Fort Smith, and ran at full capacity until early 1987. In 1988, the Cominco Mine shut down and the load on the hydro unit was reduced to a maximum operating range of approximately 13.5 MW.

Currently Taltson provides power for the towns of Fort Smith, Fort Resolution and Hay River. The load on the hydro unit is varying from 6 MW in the summer to 13.5 MW in the winter. During the winter, when the load is between 12.3 MW and 13.0 MW, the plant operates in the rough zone.

The vibration is strong enough that it can be felt by the operator in the staff housing approximately 600 feet away from the hydro unit and it is causing severe vibration on the surge tower supports. This is strong enough to create noise, and the vibration can be seen as the support struts for the surge tower shake.

The rough zone has been studied several times and monitoring equipment has been installed to verify the operational range where the zone exists. The cause of the rough zone has been attributed to the design of the turbine (Francis turbine) at the plant, specifically the wheel. Francis turbines are known to have this problem at approximately 60% load capacity.

Vibration at Taltson is negligible once the unit's load is above 13.5 MW or below 12.3 MW. Therefore, to keep the Taltson system out of the rough zone, the plant must be operated below 12.3 MW and above 13.5 MW. Operating in the rough zone has been identified as a dam safety concern as the consequences of continuing to operate the dam in this range are unknown.



ANALYSIS OF OPTIONS

Option 1: Do Nothing

Failure to act would mean that Taltson plant would continue to operate during the winter season in the rough zone. This poses a dam safety concern as the consequences of these vibrations to the plant are unknown. It puts the plant at risk and could potentially reduce its useful life. Replacing the Taltson dam would come at a considerable cost.

Option 2: Purchase and Install a Load Bank Estimated Costs: \$719,000

This option involves the purchase and installation of a load bank at the Pine Point substation. The load bank would be able to add load to the Taltson unit when the existing load on the system was between 12.3 MW and 13.0 MW, and the unit would be forced to operate in the rough zone. Additional load from the load bank would be added to push the unit out of the rough zone. As was previously noted, when the unit operates at 13.5 MW the vibrations on the system is minimal.

The main benefit of using a load bank is the Taltson system would no longer be operated in the rough zone. Operating in the rough zone causes significant vibrations and the full extent of the potential consequences are unknown. Utilizing a load bank would eliminate this dam safety risk and remove the potentially significant negative outcomes such as plant damage and reduced useful life.



Northwest Territories Power Corporation
Business Case
Pine Point Load Bank

COST ESTIMATES

Table 1 – Budget Estimates

Description	2013/14	2014/15	2015/16	2016/17
Payroll Regular	13,000	44,000	53,000	12,000
Payroll Overtime	500	500	12,000	4,000
Payroll Fringe Benefits	4,000	12,000	15,000	4,000
Consultants Lump Sum	-	-	13,000	-
Contractors Lump Sum	-	1,000	107,000	20,000
Transportation	1,000	-	5,000	-
Accommodation	-	-	500	-
Meals	-	-	1,000	-
Equipment Rentals	-	-	500	10,000
Freight	12,000	-	25,000	-
Structures & Improvements	-	-	10,000	-
Fuel Storage & Handling	-	-	8,500	-
Engines	-	-	2,000	-
Accessory Electrical Equipment	-	3,000	86,000	10,000
Misc. Power Plant Equipment	-	-	-	-
Controllers/Compensators/Lightning	141,000	-	(90,000)	-
Contingency	-	-	-	11,500
Total Base Project Estimate	\$171,500	\$60,500	\$248,500	\$71,500

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$171,500	\$6,000	\$29,000	\$206,500
2014/15	\$60,500	\$14,000	\$13,000	\$87,500
2015/16	\$248,500	\$19,000	\$60,000	\$327,500
2016/17	\$71,500	\$10,000	\$16,000	\$97,500
Total Project Cost				\$719,000



Northwest Territories Power Corporation
Business Case
Pine Point Load Bank

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.719M
- Amortization rate of 4.04%
- Return on Ratebase of 6.88%
- Allocation of costs to Taltson Zone

Given the above assumptions, the average rate impact of the project for NTPC's Taltson Zone customers is estimated at 0.763%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$719	\$899	\$1,079	\$1,438
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$29	\$36	\$43	\$58
Return on Ratebase (\$000)	\$49	\$62	\$74	\$99
Sub-Total: Revenue Requirement Increase (\$000)	\$78	\$98	\$117	\$156
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$78	\$98	\$117	\$156
Talston Zone Revenue Requirement (\$000)	\$10,248	\$10,248	\$10,248	\$10,248
Average % Rate Increase	0.763%	0.954%	1.145%	1.527%



Northwest Territories Power Corporation
Business Case
Pine Point Load Bank

SUMMARY OF BUSINESS CASE RATIONALE

There is a resonant vibration that occurs during the winter season when the load on the Taltson system is between 12.3 and 13.0 MW (rough zone), and the vibration is quite significant. This poses a dam safety concern. It puts the plant at risk and could potentially reduce its useful life.

To mitigate the risk to the Taltson plant and to be a responsible utility operator, NTPC has an obligation to act and prevent Taltson from operating in this rough zone. The Corporation has studied this issue and determined the best solution to this problem is to use a load bank.

The purpose of adding the load bank would be to add load to the Taltson system when the existing load on the system is between 12.3 and 13.0 MW (rough zone). The resulting load would then be above the higher range (13.0 MW) of the rough zone, thus eliminating the vibrations from the unit.

RECOMMENDATION

The Corporation recommends proceeding with option 2 to purchase and install a load bank at Pine Point substation. The load bank will prevent Taltson from operating in the rough zone and enable NTPC to meet its obligation to provide safe, reliable power to customers. The total costs to complete the project are estimated to be \$0.719M.



Northwest Territories Power Corporation
Business Case
Pine Point Load Bank

Attachment A

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Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
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NEED FOR PROJECT / BACKGROUND

The Inuvik power plant consists of two separate buildings, namely the K-Plant built in 1970 and the EMD Plant rebuilt in 1984 after a fire. The K-Plant houses two natural gas fuelled units and one diesel unit. The natural gas generators G11 and G12 have a combined electrical capacity of 4,900 kW and are fueled with non-scented natural gas. In 2005, the plant was modified by adding a third natural gas generator set (G10) rated at 2,800 kW. Subsequently, the G11 natural gas generator was converted to diesel. The EMD plant has four diesel generating units, two 2,500 kW EMD units, a 760 kW CAT D399 unit and a 300 kW Cummins unit. Total installed capacity at the Inuvik plant is 13,720 kW.

The Inuvik plant was one of NTPC's first plants to undergo automation in the early 1990s. The EMD plant and K-plant were both equipped with a programmable logic controller (PLC) to automate the plants. A PLC is essentially a digital computer used for automation of an industrial electromechanical process. (e.g., control of machinery, equipment).

The existing station PLCs at the EMD and K-plant are no longer supported by the manufacturers and are at the end of their useful life. The station PLCs control the plants. When there are failures of the station PLCs, the plant shuts down. The shutdown can result in an extended outage. There have been two such incidents, one incident in 2013, and the other in 2014. More failures are anticipated until such time that the existing station PLCs are replaced with a more modern solution.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option does not address the reliability issues the Inuvik plant is currently facing. By continuing to use the current station PLCs the risk of plant failure is high. This will continue to remain an issue until the existing equipment is replaced.

Option 2: Install New Station PLCs

Estimated Costs: \$495,000

This option would involve the installation of two new station PLCs, one for each plant. This would include the following steps:

- PLC Design – Complete detailed design to identify the specific PLC hardware and software required to meet the needs of plant operators and obtain the best possible performance from the plant.
- Hardware Installation – Remove existing station PLC hardware (two units), complete wiring upgrades and install new modern PLC hardware.



Northwest Territories Power Corporation
Business Case
Inuvik New Station PLC

- Software Installation:
 - Installation of upgraded HMI (Human Machine Interface) software, which is used to display critical information (e.g., alarms) to plant operators and enables operators to make equipment adjustments automatically. The existing configuration has many shortcomings and needs to be reprogrammed in order to be effective.
 - Interface – The PLC requires an interface with the plant Supervisory Control and Data Acquisition (SCADA) system.
 - The SCADA system utilizes data from the PLC system to provide outage reporting statistics and generate alarms. These would be displayed to the operator via the HMI software.
 - The SCADA system can also be accessed remotely by central resources (NTPC Central Control Room). These resources would be able to assist the plant operator in resolving problems at the plant and would have the status of the plant and equipment (data from PLC) on display in the control room

The benefit of selecting this option is that it would significantly improve the reliability of the Inuvik plant as follows:

- Outage avoidance and outage length reduction – Modern PLCs have enhanced monitoring capabilities that allow for more effective troubleshooting. This will reduce the frequency of outages and the length of outages that customers experience.
- Effective plant operation - New station PLCs would be able to provide more effective automated control over the plant.

COST ESTIMATES

Table 1 – Budget Estimates

Description	2016/17	2017/18
Payroll regular	7,000	-
Payroll fringe	3,000	-
Contractors Lump Sum	77,000	230,000
Transportation	9,000	-
Accommodation	3,000	-
Meals	2,000	-
Automation/Supervisory System	26,000	-
Contingency	-	70,000
Total Base Project Estimate	\$127,000	\$300,000



Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2016/17	\$127,000	\$0	\$18,000	\$145,000
2017/18	\$300,000	\$0	\$50,000	\$350,000
Total Cost				\$495,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.495M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.075%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

**Table 2 – Sensitivity Analysis**

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$495	\$619	\$743	\$990
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$20	\$25	\$30	\$40
Return on Ratebase (\$000)	\$24	\$30	\$36	\$48
Sub-Total: Revenue Requirement Increase (\$000)	\$44	\$55	\$66	\$88
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$44	\$55	\$66	\$88
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.075%	0.094%	0.113%	0.151%

SUMMARY OF BUSINESS CASE RATIONALE

The Inuvik plant is one of NTPC's first plants to undergo automation in the early 1990s. The K-plant and EMD plant at Inuvik both utilize PLCs to run the plants autonomously. The existing station PLCs at the plants are no longer supported by the manufacturers and are at the end of their useful life.

When the station PLCs fail, it will cause a plant shut down and could result in an extended outage. There have been two such incidents thus far, with more failures anticipated until such time that the existing station PLCs are replaced with a more modern automation solution.

RECOMMENDATION

It is recommended the Corporation proceed with the replacement of the station PLCs at the Inuvik plant with updated PLC hardware and software as outlined in option 2. This will enhance the reliability of the plant as the use of more modern PLCs will reduce the frequency of outages and their length. The total costs to complete the project are estimated to be \$0.495M.



Attachment A

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A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

The Public Utilities Board (PUB) requested that the Corporation develop a plan to improve the reliability of the Yellowknife system. One of the commitments made was to install electronic governors on all the hydro units. To date, electronic governors have been installed on the Snare Falls and the two Snare Forks units. This project is required to continue with the program of reliability improvements and install an electronic governor at Snare Cascades.

The main benefits of this project are:

- The improved response during system hunts will help to reduce the outages on the Snare System. Typically there are at least one or two total outages caused by system hunts that an electronic governor will be able to control.
- The governor is critical for stable start-up, control and operation of the Snare Cascades hydro unit. The current control and governing system at Snare Cascades is very old technology and it is becoming difficult to find technicians capable of maintaining and repairing it.
- The electronic governor will make trouble shooting from a distance possible, which will enable much faster return to service when a unit is experiencing problems.
- The control system is the same as that installed for Snare Falls and Snare Forks and this will provide a common control platform across the main units at Snare making operator training much easier and consistent.
- Converting the Snare Cascades plant to digital control technology utilizing off the shelf control components will provide a control system that can be maintained easily. This will eliminate the need to hire from an increasingly small pool of technicians who are able to maintain the current unit.

The governor is critical for stable start up, control and operation of the Snare Cascades hydro unit. If a problem develops with the governor, it would likely take at least three days to get a technician capable of fixing the problem to site and potentially much longer. Snare Cascades is the third unit on the run of the river Snare system and so if this unit is forced into a shutdown, it becomes necessary to run diesel and/or spill water while waiting for a technician. Spilled water takes about three days to reach the next plant at Snare Forks. A forced outage on the Snare Cascades unit due to a governor failure would result in at least three days running of the Jackfish diesel plant, which would cost approximately \$40,000 per day (seasonally dependent).

The Corporation has also made a commitment to the PUB that all governors will be upgraded to digital technology – the PUB required this as part of the overall plan to upgrade the Snare/Yellowknife system and improve reliability.



Northwest Territories Power Corporation
Business Case
Snare Cascades – New Electronic Governor

BACKGROUND

The Snare / Yellowknife system consists of four hydro plants on the Snare River: Snare Rapids, Snare Falls, Snare Cascades and Snare Forks; 2 hydro plants on the Yellowknife River: Bluefish G1 and G2; and the Jackfish diesel plant.

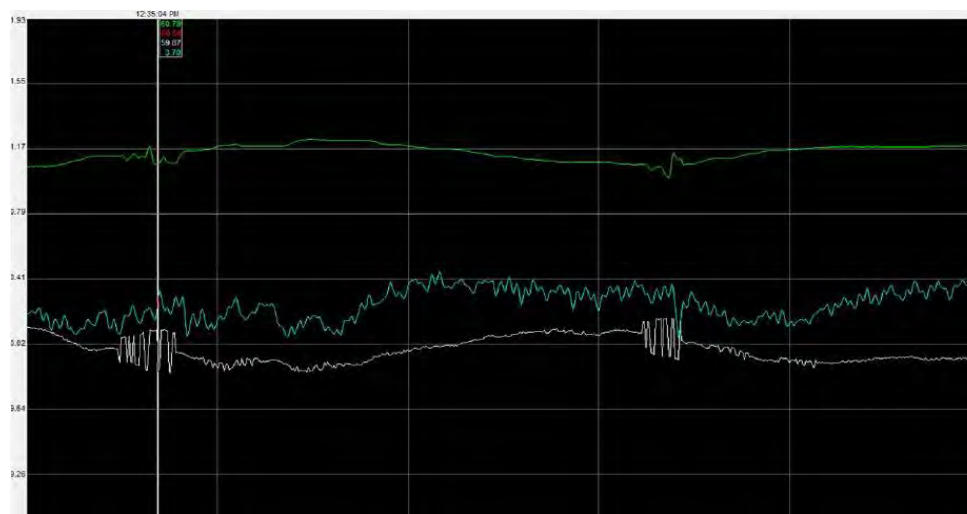
The Snare / Yellowknife system has gone through many load changes throughout the years. After shutting down the gold mines in Yellowknife in the early 2000s, the city's commercial and residential customers now make up the majority of the load. Also the change in distribution voltage by NUL from 4.16 kV to 25 kV has resulted in larger loads on a smaller number of feeders.

Historically, there have been many instability issues on the Snare Hydro system, where units hunt and are unable to hold load or shut down in a controlled manner. The Snare/Yellowknife system instability/load shedding was reviewed by three consultants over the years. One of the top recommendations for improvements is the upgrade of the governor systems to digital governors.

The Snare Forks (units 1 and 2) and Snare Falls plants have recently been converted from hydro-mechanical governors to electronic governors. Although the Yellowknife system still is experiencing system-wide uncontrolled and unpredictable swings, the new governors are enabling very accurate system analysis and will also have the ability to dampen down the instabilities.

The older technology was a factor in extending the December 29, 2013 outage. The older technology governors were previously replaced on the Snare Falls and Snare Forks (x2) units.

The type of data recently obtained from the electronic governors at the Snare Falls and Snare Forks can be seen below where the white line is the start of a system hunt that on this occasion did not develop into full scale instability – the green line shows the governor gates responding to and correcting the disturbance.





Northwest Territories Power Corporation
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Snare Cascades – New Electronic Governor

The Snare Cascades hydro plant governor system is very old technology. The Corporation relies on contractors to service and repair the governor and there are now a limited number of experienced and qualified technicians available who are capable of working on these units. The contractor(s) hired for the maintenance are often retired technicians who used to work for the original equipment manufacturer (Woodward).

ANALYSIS OF OPTIONS

Option 1: Do Nothing

This option is not recommended. NTPC will continue to have instability issues in the hydro system, which causes outages and frequency problems. The risk of an extended outage and the associated high diesel costs will continue until the Snare Cascades hydro plant is upgraded with new electronic governors.

Option 2: Design and Install a New Electronic Governor

Estimated Costs: \$2,500,000

The existing hydro mechanical governor will be replaced with digital technology. This will include:

- A standalone PLC based digital governor with a local touch screen and standard mimics for operator interface.
- An integrated unit controller that will replace existing analogue meters, switches and relay logic. It will consolidate all control, monitoring, alarms and local/remote starting.
- A new PC based Human Machine Interface that will provide enhanced local control and monitoring for every aspect of a unit start/stop and on-line control with trouble shooting screens and a historian.
- Complete interface to the existing SCADA system.

Upgrading to digitally controlled governors will provide the Corporation with the following benefits:

1) Improved system reliability:

- Reduce the probability of the governor system failing and decrease the consequences in the event of future failures. The older technology, for example, extended the long outage on December 29, 2013 since a relay on the existing governor failed and it took several hours to trouble shoot and fix the problem. This would not have happened with a digital governor. The ability to bring the unit back online more quickly will reduce the need for diesel generation with a potential savings of over \$300,000 if the governor fails and requires us to locate an experienced technician to Snare to make the repair.



Northwest Territories Power Corporation
Business Case
Snare Cascades – New Electronic Governor

- Improve response time during step load changes thus potentially improving system stability. The control is much faster than the hydraulic governor, which relies on moving dash pots, needles and various linkages, which very quickly lose their accuracy due to wear.
- Improve the long term ability to tie the governor systems together and permit the multiple hydro units to respond similar to a single large unit, which is the equivalent to an integrated synchronization system. This is particularly important with the larger loads on town feeders from the 25 kV distribution upgrade.
- Provide a common control platform for all the larger units at Snare, which will result in less training and a lower chance of operator error, particularly as our more experienced operators are now retiring and the intuitive and standard control systems offered by converting to digital technology will be very important in training new operators.
- Permit simplified and improved local and remote trouble shooting capability. This is already proving valuable for the governors already converted.

2) Other operational benefits:

- Remove the reliance on external contractors to service and maintain a key piece of equipment. The skills required to maintain the older technology is also rapidly disappearing as most hydro plants throughout North America have converted to digital technology
- Improved ability to undertake accurate system modelling for reliability planning. Currently with the older hydro-mechanical governors it is very difficult to model the system since its performance changes during the year as components wear. The digital governor will enable more accurate modelling for the system with predictable load response characteristics.

Option 3: Refurbish Existing Governor

The cost of this option was not estimated given it is not a reasonable approach. The existing parts are very difficult to find, mechanical control systems are less reliable than modern electronic governors and more costly to maintain.



Northwest Territories Power Corporation
Business Case
Snare Cascades – New Electronic Governor

COST ESTIMATES

Table 1 – Budget Estimates

Description	2015/16	2016/17
Payroll Regular	20,000	10,000
Fringe Benefits	7,000	4,000
Consultants Lump Sum	158,000	525,000
Transportation	-	5,000
Accommodation	-	1,000
Meals	-	1,000
Freight	10,000	-
Governor	820,000	-
Contingency	270,000	144,000
Total Base Project Estimate	\$1,285,000	\$690,000

Project Estimated Cost:

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2015/16	\$1,285,000	\$46,000	\$282,000	\$1,613,000
2016/17	\$690,000	\$46,000	\$151,000	\$887,000
Total				\$2,500,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 60 years at the currently approved GRA amortization rates.

The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$2.50M.
- Amortization rate of 1.67%.
- Return on Ratebase of 7.18%.
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.595%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
Snare Cascades – New Electronic Governor

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$2,500	\$3,125	\$3,750	\$5,000
Amortization Period (Approx. Year)	60	60	60	60
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$42	\$52	\$63	\$84
Return on Ratebase (\$000)	\$180	\$224	\$269	\$359
Sub-Total: Revenue Requirement Increase (\$000)	\$221	\$277	\$332	\$443
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$221	\$277	\$332	\$443
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.595%	0.744%	0.893%	1.190%

SUMMARY OF BUSINESS CASE RATIONALE

The Snare Hydro system has historically suffered from instability issues that resulted in power outages, which could have been prevented if an electronic governor was in place. The Corporation developed a plan at the request of the PUB, to improve the reliability of the Yellowknife system. As part of the plan to achieve this goal, NTPC upgraded mechanical governors to electronic governors at its Snare Falls and Snare Forks hydro facilities. The mechanical governors operating at the Snare Cascades hydro plant are old technology and due to be replaced. The installation of the electronic governors will improve system reliability by reducing the probability of the governor failing, improved response time during load changes, more integrated governor system, remote trouble shooting and reduced operator training (common platform).

RECOMMENDATION

It is recommended to proceed with the installation of the electronic governor system at Snare Cascades as outlined in option 2.



Attachment A
Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 6.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

This project entails the mechanical overhaul of the generator and turbine assembly at unit 1 of the Snare Falls Hydro Generation facility. The project will address the following issues:

1. **Unit is scheduled for a major overhaul:** The last major overhaul at Snare Falls was conducted approximately 20 years ago (1995). Given the scope of the 1995 overhaul a 20 year life is considered somewhat premature. Additional years of service may have been possible if not for the change in operating conditions that caused excessive wear described in background section of this document.
2. **Environmental compliance:** In 2014 the Corporation submitted a spill report to the federal government indicating that a release of lube oil had occurred, due to a malfunction in the unit's lower lubricating system. This overhaul includes the installation of greaseless bearings and bushings, improved continuous trunnion seals, lift pump, instrumentation and possible use of biodegradable oil in the turbine runner hub. These choices will provide durable, reliable and environmentally friendly operation of the unit for several decades.
3. **Address Immediate Limited Operability Status:** The unit has been operating at 53% of rated capacity since a temporary repair in March 2015. This repair allowed operation to resume after a complete unit failure in February 2015.

Conditions of the unit based on March 2015 inspection, after failure:

- a) Inoperable blades: variable blade angle control mechanism is inoperable, reducing efficiency and operating flexibility of the unit. Blades are currently fixed at an angle allowing for operation at 53% of rated.
- b) Risk of leakage of grease/oil past wicket gate mechanism and blade trunnion seals into water.
- c) Grease-type generator thrust bearing (GTB) experiences high wear during start-up.
- d) Marking of draft tube discharge/throat ring by contact with runner in the past possibly caused by turbine guide bearing (TGB) wear and powerhouse movement.
- e) Blade cavitation beyond what is considered normal.
- f) Generator stator and rotor windings are dirty and may require some minor repairs subject to close inspection.
- g) Instrumentation deficiencies. Improve monitoring to avoid repeat of this failure.



BACKGROUND

The Snare Falls hydro plant and airstrip (630 26' N, 1160 11' W) is located 15 km southwest of Snare Rapids. The rated plant capacity is 7.4 MW and is the second of four facilities on the Snare Hydro System. This comprises approximately 20% of the total hydro capacity supplying Yellowknife.

The plant sits directly below the Snare Falls Dam with the substation immediately east of the plant. The headgate sits west of the plant and two spillway gates control flows through the spillway. The tie substation sits approximately 200m east of the plant.

The plant was originally commissioned in 1961. A major overhaul was performed on the unit in 1995 thru to 1997, including a generator stator rewind. In 2013 a new digital governor supplied by American Governor was installed replacing the original mechanical Woodward Governor.

In May 2014 Snare Falls turbine was not governing correctly and during a subsequent inspection it was found that oil was leaking past the blade trunnion seals. To temporary correct the problem, the turbine blades were welded in place (at 85% steep blade angle) and the hub was filled with grease (typically the blade angle is governed depending on the loading on the unit). As expected by our Engineers, this introduced a rough zone in the partial load operating range of the unit and plans were put in place to operate the unit outside of this zone until an overhaul of the unit could be planned and implemented.

As the 2014 year progressed it became apparent that the Snare system had entered a drought period causing low water conditions. With less water, the unit was being forced to run at lower loads, bringing it closer to the rough zone. To mitigate this, the unit was run at higher loads for 12 hours a day and shut down for 12 hours a day.

In February 2015 the Turbine Guide and Generator Thrust Bearings failed. The factors ultimately contributing to the failure included:

- Frequent starting and stopping due to the combination of low water conditions and the blades being fixed in May 2014.
- Failed grease line to the Turbine Guide Bearing that likely contributed to wear.
- Wear and dimensional variation of the thrust bearing support springs would have led to uneven or unequal support of the thrust pads.

In March 2015 the unit was put back into service with new bearings and the blades stopped at 45% steep blade angle using steel blocks welded to the runner hub. This allowed for smooth operation



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Business Case
Snare Falls Mechanical Overhaul

at lower loads so there was no longer the need to daily start stop the unit. The Corporation began the process of scoping, costing and obtaining board approval for a major overhaul.

Environmental Concerns

Further, in 2014 the Corporation submitted a spill report to the federal government indicating that a release of lube oil had occurred due to a malfunction in the unit's lower lubricating system. As a result, in September 2014 NTPC received a written warning from Environment Canada that the Corporation was in contravention of subsection 36(3) of the Fisheries Act. The warning states it is intended to bring the issue to the Corporation's attention in order that corrective action can be taken to ensure compliance with the Fisheries Act.

Failure

As the 2014 year progressed it became apparent that the Snare system had entered a drought period causing low water conditions. With less water, the unit was being forced to run at lower loads, bringing it closer to the rough zone. To mitigate this, the unit was run at higher loads for 12 hours a day and shut it down for 12 hours a day.

In February 2015 the turbine guide, generator guide and thrust bearings failed. The mechanism of failure was found to be a failed grease line to the turbine guide bearing (TGB). This resulted in increased clearance at the TGB which, in turn, lead to damage at the Thrust and generator guide bearings. This coupled with a change in operating conditions of daily start stops lead to the ultimate failure of the thrust and generator guide bearings. The start / stops cause additional wear on the thrust bearing and once it failed the unit could not be run.

In March 2015 the unit was put back into service with new bearings and the blades stopped at 45%. This allowed for smooth operation at lower loads so there was no longer the need to intermittently operate the unit. This was considered a temporary measure with the knowledge that this unit was scheduled for a major overhaul in the summer of 2015.

A detailed condition assessment after the failure identified the following concerns that could negatively impact plant reliability.

- Variable blade system not operational.
- Runner contact with the draft tube throat ring.
- Blade cavitation beyond what is considered normal.
- High lift system required to prevent thrust bearing wear.
- Instrumentation deficiencies.
- Oil leaking at low bracket



ANALYSIS OF OPTIONS

The Corporation reviewed the following options with respect to the issues identified with the power plant.

Option 1: Do Nothing

This option is not recommended.

Continuing operating with the status quo is not a reasonable option for consideration. Under this option, reliability for the communities in which the Snare Falls services will be impaired and risk for extended power outages. Additionally, further deterioration of the units will occur and compound the problems that currently exist. The “Do Nothing” option will simply reduce the unit’s operational reliability and result in increased rehabilitation costs at a later date. Failure to immediately overhaul this unit will also mean a larger proportion of diesel generation going forward.

Option 2: Replace with New Generating Unit

This option is not recommended. Costing was not investigated.

Based on the existing condition of the turbine unit, the complete replacement could be considered, however current lead times for unit delivery would delay the project by approximately 12-18 months. As this unit is a priority, waiting this additional delivery time is not considered an appropriate option. The deficiencies found with the unit can be successfully remedied and sufficiently extend the operational life of the unit upon completion of a mechanical overhaul.

Option 3: Partial Overhaul

A Partial Overhaul may restore blade operation and complete some other high priority work, but this may not fully restore reliability with the risk of a forced outage or the requirement to perform other unscheduled maintenance with associated diesel operating costs. The cost of forced outages or additional unscheduled maintenance work may exceed the incremental cost of the subject major overhaul.

Option 4: Major Overhaul

This option offers a number of benefits to the Corporation’s customers, including:

- Reduced risk of power outages and improved reliability of service
- Improved operating characteristics for the power plant
- Operational savings due to improved efficiency of an overhauled unit.



Scope of Work

- a) Full disassembly of the unit
- b) Refurbishment of the runner blades and hub
- c) Conversion of the wicket gates and its operating mechanism to greaseless operation
- d) Conversion of turbine guide bearing to greaseless
- e) Conversion to biodegradable oil for hub (being researched)
- f) Improved trunnion seals
- g) Static lubrication of thrust bearing
- h) Generator stator and rotor inspection/testing and repairs
- i) Instrumentation upgrades
- j) Re-assembly and commissioning

The above scope of work has been submitted to Voith and we have received a firm proposal to complete this work as budgeted below. This includes sending the unit's runner hub to Voith's York, PA facility for repair and modification.

In order to undertake the project, an outage of approximately 18-20 weeks would be required. It is recommended this outage occur during periods when consumption levels are typically low, to allow the system to accommodate the load requirement with the reduced generation.

Failure to complete the major overhaul will significantly impact hydro generation and the need to replace that generation with compensating diesel. Table 1 below illustrates the impact of running under normal operation vs. the current situation. The numbers represent diesel offset through generation at Snare Falls. Current operational limits would require approximately \$4.9M of incremental diesel to meet load requirements versus normal operation.



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Table 1 – Equivalent Diesel Offset Snare Falls

Current Operation (limit 4MW)

Load	Days	Month	kWhs Required	Equiv. Litres Fuel (litres)	Equiv. Cost Fuel per GRA	Total Equiv. Cost per Month
4.0 MW	30	June	96000	26301	\$ 27,012	\$ 810,345
4.0 MW	31	July	96000	26301	\$ 27,012	\$ 837,357
4.0 MW	31	August	96000	26301	\$ 27,012	\$ 837,357
4.0 MW	30	Sept	96000	26301	\$ 27,012	\$ 810,345
4.0 MW	31	Oct	96000	26301	\$ 27,012	\$ 837,357
4.0 MW	30	Nov	96000	26301	\$ 27,012	\$ 810,345
4.0 MW	31	Dec	96000	26301	\$ 27,012	\$ 837,357
4.0 MW	31	Jan	96000	26301	\$ 27,012	\$ 837,357
4.0 MW	28	Feb	96000	26301	\$ 27,012	\$ 756,322
4.0 MW	31	Mar	96000	26301	\$ 27,012	\$ 837,357
4.0 MW	30	Apr	96000	26301	\$ 27,012	\$ 810,345
4.0 MW	31	May	96000	26301	\$ 27,012	\$ 837,357

Total \$ 9,859,200.00

Regular Operation

Load	Days	Month	kWhs Required	Equiv. Litres Fuel (litres)	Equiv. Cost Fuel per GRA	Total Equiv. Cost per Month
5.7 MW	30	June	136800	37479	\$ 38,491	\$ 1,154,742
5.6 MW	31	July	134400	36822	\$ 37,816	\$ 1,172,299
5.2 MW	31	August	124800	34192	\$ 35,115	\$ 1,088,564
4.9 MW	30	Sept	117600	32219	\$ 33,089	\$ 992,673
5.6 MW	31	Oct	134400	36822	\$ 37,816	\$ 1,172,299
6.2 MW	30	Nov	148800	40767	\$ 41,868	\$ 1,256,035
6.8 MW	31	Dec	163200	44712	\$ 45,920	\$ 1,423,506
7.4 MW	31	Jan	177600	48658	\$ 49,971	\$ 1,549,110
7.0 MW	28	Feb	168000	46027	\$ 47,270	\$ 1,323,564
6.6 MW	31	Mar	158400	43397	\$ 44,569	\$ 1,381,639
6.2 MW	30	Apr	148800	40767	\$ 41,868	\$ 1,256,035
4.8 MW	31	May	115200	31562	\$ 32,414	\$ 1,004,828

Total \$ 14,775,294.25

Regular operation fuel displacement cost 14,775,294.25

Blades welded fuel displacement cost 9,859,200.00

Total	\$ 4,916,094.25



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Business Case
Snare Falls Mechanical Overhaul

COST ESTIMATES

The total cost of the project is estimated at \$10.5 million. Table 2 provides a breakdown of the cost estimates/

Table 2 - Project Cost Breakdown

NTPC Labour		385,000
Consultants		100,000
Contractors	Voith	4,000,000
Expenses		240,000
	Total Direct	4,725,000
Contingency	Approx. 20%	800,000
	Total Incl. Contingency	5,525,000
Overhead	13%	718,250
	Total Overhaul	6,243,250
Fuel	1 June - 31 Oct	2,900,000
Fuel Contingency	1 Nov - 30 Nov	1,300,000
	Total Fuel	4,200,000
Overhead on Fuel	0%	0
	Total Fuel	4,200,000
	Total Overhaul and Fuel	10,443,250



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RATE IMPACTS

The project will not have any impact on rates until the time of the next general rate application. Rate impacts will be largest early in the project's life, since accumulated amortization will reduce the return on ratebase impacts. The rate impacts were estimated based on the following assumptions:

- Amortization expense of \$0.157 million.¹
- Return on ratebase of \$0.750.²

Table 3 summarizes the calculation of the estimated incremental revenue requirement increase due to the project of approximately \$0.9 million. The average rate impact of the project for Snare rate zone customers is estimated at 2.5%.³ The project will have no rate impacts until the time of the Corporation's next GRA. The project will have no impact on customer rates in other zones. The sensitivity analysis in table 4, examines the impacts on rates of various cost scenarios.

Table 3 - Project Estimated Rate Impact

Project Characteristics	
Capital Cost (\$ 000)	10,443
Amortization Rate	1.54%
GRA Approved Return on Ratebase	7.18%
Revenue Requirement Impacts	
Amortization Expense (\$ 000)	161
Return on Ratebase (\$ 000)	750
Sub-Total: Revenue Requirement Increase	911
O&M Savings Expected	0
Total Revenue Requirement Impact (\$ 000)	911
2013/14 Snare Zone Revenue Requirement (\$000)	\$ 36,628
Average Percentage Rate Increase	2.5%

¹ Based on 2012/14 GRA approved Hydro asset average amortization rate. .

² Based on mid-year ratebase of the project and 7.18% rate of return on ratebase approved for the Snare zone (2012/14 GRA).

³ The project's incremental revenue requirement divided by Snare zone revenue requirement of \$36.628 million.



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Business Case
Snare Falls Mechanical Overhaul

Table 3 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$10,443	\$13,054	\$15,665	\$20,886
Amortization Rate	1.54%	1.54%	1.54%	1.54%
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$161	\$201	\$241	\$322
Return on Ratebase (\$000)	\$750	\$937	\$1,125	\$1,500
Sub-Total: Revenue Requirement Increase (\$000)	\$911	\$1,138	\$1,366	\$1,821
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$911	\$1,138	\$1,366	\$1,821
Snare Zone Revenue Requirement (\$000)	\$36,628	\$36,628	\$36,628	\$36,628
Average Percentage Rate Increase	2.5%	3.1%	3.7%	5.0%

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation has a need to address the reliability and environmental compliance requirements for the Snare Falls plant. This unit supplies 7.4 MW of reliable power to an already capacity strained system. A major overhaul will allow for variable blade functionality for efficiency gains, minimize the potential for future lube or grease spills into watersheds, and provide reliable generation. While some of these gains could be achieved with a partial overhaul or a complete unit replacement; a major overhaul is considered to most cost effective option to meet these requirements.

RECOMMENDATION

It is recommended the Corporation proceed with the proposed project under Option 4. Total project costs to perform a major overhaul of Snare Falls Unit 1, including incremental fuel are estimated at \$10.5M.



Northwest Territories Power Corporation
Business Case
Snare Falls Mechanical Overhaul

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses Estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>RFC related benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on previous page.</i>
A discussion of all intangible benefits.	<i>Intangible benefits including reduced emissions are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>

NEED FOR PROJECT

The Corporation is proposing to undertake a project to install Class 3 lightning arrestors on its L199 transmission line that connects to Yellowknife. It is an industry standard practice that a transmission line is protected from lightning by shield wires strung at the top of the transmission line. There is a 16.5 km section of the L199 transmission line that has had the shield wire removed. Recent operating experience with the line indicates a large number of outages due to lightning strikes on the unshielded line segment of the transmission line. This project addresses the reliability issues with the unshielded portion of the line.

BACKGROUND

The L199 transmission line is a 145 km (115 kV) transmission line that connects the Snare Hydro system plants to the city of Yellowknife. It is an industry standard to have transmission lines protected from lightning by shield wires strung at the top of the transmission line. However, during the winter season, ice build-up along a 16.5 km section of the line caused the shield wire to sag into the conductor resulting in phase to ground flashovers and line outages. The shield wire was removed from a 16.5 km segment of line and arresters were installed to protect against flashover from direct lightning strikes to the conductor. The removal of the shield wire eliminated the shield wire to conductor clearance issues but resulted in winter outages. However, summer outages have also increased due to the lightning strikes to the unshielded line segment.

NTPC retained Power Engineers to undertake an engineering study to investigate options for addressing the reliability issues on the line and determine the cost to re-install double shield wires in the transmission line to also address the previous issue of using shield wires.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

Continuing operating with the status quo is not a reasonable option for consideration. Under this option, reliability for the communities on the Snare system will continue to be impaired.

Option 2: Install Class 3 Lightning Arrestors

Estimated Costs: \$1,155,000

This option involves installing arrestors in all phases on every tower of the unshielded portion of the line. This will address reliability issues resulting from lightning strikes on the unshielded portion of the line. This option was recommended in the Power Engineers study.

Option 3: Reinstall Shield Wires

This option would involve reinstalling shield wires in a manner that avoids the winter sagging issues previously experienced on this segment of the line. This would involve increasing the size and/or tension of the shield wire. This option is not considered feasible because it voids the CSA specified tension limit.

COST ESTIMATES

Table 1 – Budget Estimates

Description	2013/14	2014/15	2015/16	2016/17
Contractors	48,000	83,000	220,000	500,000
Project Management	-	-	20,000	47,000
Total	\$48,000	\$83,000	\$240,000	\$547,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2013/14	\$48,000	\$1,500	\$10,500	\$60,000
2014/15	\$83,000	\$5,000	\$18,000	\$106,000
2015/16	\$240,000	\$14,000	\$53,000	\$307,000
2016/17	\$547,000	\$37,000	\$98,000	\$682,000
Total Project Cost				\$1,155,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 47 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.968M
- Amortization rate of 2.15%
- Return on Ratebase of 7.18%
- Allocation of costs to Snare Zone

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.29%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$1,155	\$1,444	\$1,733	\$2,310
Amortization Period (Approx. Years)	47	47	47	47
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$25	\$31	\$37	\$50
Return on Ratebase (\$000)	\$83	\$104	\$124	\$166
Sub-Total: Revenue Requirement Increase (\$000)	\$108	\$135	\$162	\$216
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$108	\$135	\$162	\$216
NTPC Total Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average Percentage Rate Increase	0.29%	0.36%	0.43%	0.58%

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation has a need to address the reliability issues on the Snare transmission system. The shield wires were removed from a 16.5 km section of the L199 transmission line causing outages from lightning strikes to the unshielded section. A technically feasible option was identified and recommended based on an engineering study commissioned by NTPC. Installing lightning arrestors will protect the transmission line and help prevent outages from lightning strikes.

RECOMMENDATION

It is recommended the Corporation proceed with the installation of Class 3 lightning arrestors as outlined in option 2.

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Option section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Ulukhatok Main Fuel Storage Tank

NEED FOR PROJECT

The Corporation is proposing to undertake a project to acquire and install a new main fuel tank for the Ulukhaktok power plant. The current tank is past its useful life and in an unsafe state. Significant surface corrosion has been noted on the tank and its condition is now below the requirements for various regulatory codes and best practices. The safety and reliability of the tank makes replacing it essential to prevent a major diesel spill from occurring.

BACKGROUND

The existing single wall main fuel storage steel tank was first installed in 1976 and is over 35 years old. In 1992, the tank was moved out of a small gravel berm into a metal berm. Over the years, metal corrosion from the sea salt in the air and the age of the tank, including the metal berm has led to extreme surface corrosion. The surface corrosion on the storage tank and the berm are not repairable and NTPC employees have submitted safety concern reports on the tank and berm condition. The existing tank and the metal berm no longer meet applicable environmental and other related codes and best practices. The current state of the old tank and berm negatively affect the overall reliability of the diesel plant.

The Corporation monitors regulatory requirements and incorporates these requirements into the 5 year Capital Program. This program replaces/upgrades assets as required to ensure NTPC meets existing regulatory codes. In addition, the Capital Program is updated as regulatory changes occur, ensuring the Corporation continues to meet regulatory requirements.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

This option is not a viable given the existing tank and metal berm are structurally unstable. They are both long past their life expectancy and no longer comply to the latest applicable Underwriters Laboratories of Canada (ULC) standards and other related codes.

Option 2: Installation and commissioning of a new Fuel Storage Tank

Estimated Costs: \$552,000

This option consists of the acquisition, installation and commission of a new main fuel tank for the Ulukhaktok plant. This project is part of a corporate initiative to upgrade the fuel tanks, piping, and related systems at diesel based plants. These upgrades will enhance plant safety, reliability and ensure compliance with current regulatory requirements. Consistent with this policy the proposed project would take place over two years and consist of the following:

1. 2016:
 - a. Purchase new fuel tank and related components:
 - i. Double walled 90,000 liter fuel storage steel tank
 - ii. Piping



Northwest Territories Power Corporation
Business Case
Ulukhatok Main Fuel Storage Tank

- iii. Pumping system
 - b. The new tank and its related components to be shipped to Ulukhaktok via barge
 - 2. 2017:
 - a. Installation and commissioning of the new main fuel tank, along with new piping and pumping system, connected to the plant's day tank.

The completion of the project outlined above will allow NTPC to realize the following benefits:

- 1) The new storage tank meets the latest applicable codes and regulatory requirements.
- 2) Purchase of a double walled fuel tank eliminates the need for a metal berm and its associated cost.
- 3) The new tank will substantially reduce the risk of fuel spills and the associated environmental damage caused by such spills.

COST ESTIMATES

Table 1 – Budget Estimates

Description	2015/16	2016/17
Fuel Tank	\$80,000	-
Fuel System Materials	\$8,000	-
Freight	\$21,500	-
Mechanical Equipment	-	\$66,000
Electrical Equipment	-	\$15,500
Fencing	-	\$32,500
Contractors Lump Sum	-	\$77,000
Equipment Rental	-	\$15,500
Engineering Regular	-	\$35,000
Engineering OT	-	\$4,000
Fringe	-	\$12,000
Civil Works	-	\$58,000
Contingency	-	\$32,000
Total	\$109,500	\$347,500

Project Cost Estimate



Northwest Territories Power Corporation
Business Case
Ulukhatok Main Fuel Storage Tank

Budget Year	Annual Budget Estimate	IDC	Overhead	Total Annual Cost
2015/16	\$109,500	\$3,500	\$12,000	\$125,000
2016/17	\$347,500	\$3,500	\$76,000	\$427,000
Total Cost				\$552,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.552M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.084%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost	\$552	\$690	\$828	\$1,104
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense	\$22	\$28	\$33	\$45
Return on Ratebase	\$27	\$34	\$40	\$54
Sub-Total: Revenue Requirement Increase	\$49	\$61	\$74	\$98
Less: Estimated O&M Savings				
Total Revenue Requirement Impact	\$49	\$61	\$74	\$98
Thermal Zone Revenue Requirement	\$58,418	\$58,418	\$58,418	\$58,418



Northwest Territories Power Corporation
Business Case
Ulukhatok Main Fuel Storage Tank

Average Percentage Rate Increase	0.084%	0.105%	0.126%	0.168%

SUMMARY OF BUSINESS CASE RATIONALE

The current main fuel tank at Ulukhaktok power plant is past its useful life and in an unsafe state. Metal corrosion from sea salt and air makes the replacement of the 35-year-old fuel storage tank a priority for NTPC. The corrosion has made the fuel tank fall below the codes for best practice and has created safety concerns for NTPC employees. The tank is also unrepairable with a risk of a diesel leak, which could cause significant environmental damage. The new tank will reduce the risk of fuel spills and eliminate the need for a metal berm. The proposed project plan would take place over two years as outlined in the case.

RECOMMENDATION

It is recommended the Corporation proceed with the proposed project to purchase and install a new main fuel tank for the Ulukhaktok plant as outlined under option 2. The total costs to complete the project are estimated at \$0.552M.



Northwest Territories Power Corporation
Business Case
Ulukhatok Main Fuel Storage Tank

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>Intangible benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

The Corporation is proposing to complete a project to replace NTPC's outdated automatic meter reading system and problematic manual meter reading process with current industry standard 2-way electronically controlled meters. This project would provide benefits to customers and to the internal operations of NTPC.

BACKGROUND

NTPC currently relies on two methods for recording and entering revenue meter readings into the billing system. In larger communities NTPC uses an automatic meter reading system which receives the meter read approximately once per day transmitted over a power line carrier. In smaller communities, NTPC require staff to physically go to each meter and record the meter reading. In both cases NTPC staff, are required to install or remove the meter when a customer moves in, moves out or is disconnected for failing to pay their account.

NTPC installed Hunt Technologies automatic meter reading system in the larger communities between 1996 and 2004. This system uses the electrical power lines to carry an electronic signal from the customer's meter to a receiver in the power plant to record energy consumption. This technology allowed NTPC to access meter readings electronically and eliminated the need for comprehensive manual meter reading by the line crew.

This meter reading system had many years of successful operation but now has several issues:

- Recertification - The meters installed now require re-certification to be compliant with Measurement Canada requirements. Recertification of the current meters would be costly and have significant operational issues as they must be brought out of service to be certified.
- Manual meter reading - Degradation in signal quality has resulted in up to the need to provide manual reads each month
- Technology obsolescence - Meters which work on this technology are no longer available and the supplier no longer supports this technology
- Meter failures – The current meters in operation are starting to fail with more meters expected to fail over time. This problem has become critical in Fort Smith. A separate case has been prepared for that community regarding replacement of the current meters with new intelligent meters.
- Revenue Losses - As meters fail and customers utilize power, the energy usage is not recognized by the meter, which results in a loss of revenue as the usage is not captured and there is no practical way to assess the customer's energy usage.

All smaller communities rely on plant superintendents to physically read each meter every month, record the read on a meter reading sheet, sends the sheet into the billing clerk who manually enters the reads.



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

In 2016 NTPC initiated an evaluation project in Jean Marie River to evaluate the Landis & Gyr, Gridstream RF 2-way meter system. This project is now operating successfully. This product has a strong track record with successful operation in other extreme weather areas including Edmonton, Northern Quebec, and Nunavut.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

Due to Measurement Canada requirements, the revenue meters being used in the larger communities require re-certification or replacement in the near future. NTPC does not have enough meters in its inventory for a systematic re-certification program. Also, replacement meters that work with this technology are not available. Failing meters and lack of vendor support for the existing technology requires that the existing automatic metering infrastructure be retired and a suitable replacement found.

The Corporation does have the option to continue with the status quo in the smaller communities and continue with manual reading of standard meters. The standard meters in the smaller communities are able to adequately measure power usage by customers and continued manual reading would not affect the cost operation in these areas.

Option 2: Replace Current Automatic Meters with Standard Meters Estimated Costs: \$3,263,000

This option would involve replacing the current automatic-meters (AMI) in the larger communities with standard meters. The exception would be Fort Smith for which a separate case has been prepared.

Replacing the failing AMI system with standard manually read meters would require \$416,000 in meter replacement costs over the next 3-5 years and would increase the labour required for manual meter reading by \$320,000 annually. Consumption data would no longer be available.

Utilizing these costs a present value (PV) analysis was completed (Table 1) to estimate the total lifecycle cost of using standard meters. To calculate the Lifetime Meter Reading Costs it was assumed that the manual meter reads would start in year 4 of the 20 year evaluation period for this option. The new intelligent meters are expected to last 20 years and for consistency this was the basis for evaluation of the standard meters.

This results in 17 years of manual meter reading over the evaluation period. It was also assumed that meter reading costs would increase by 2% each year over the 17 years. The Standard meter implementation was assumed to start and end in year 4. These lifetime costs estimates were then discounted at NTPC's current overall return on Ratebase, 6.88%. The estimated present value cost of using Standard Meters would be \$3.263M.



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

Table 1 – Project Cost Estimate – Standard Meters Larger Communities

Project Characteristics	Base Estimate
NTPC Return Required	6.88%
Expected Life New Meters (Years)	20
Lifetime Meter Reading Cost (\$000)	\$6,404
Standard Meter Capital Cost (\$000)	\$416
PV of Lifetime Meter Reading (\$000) [A]	\$2,944
PV of Standard Meter Capital Cost (\$000) [B]	\$319
PV Total Project Cost (\$000) [C = A + B]	\$3,263

The annual meter reading expense is the main driver of the cost of this option, and is quite substantial as the line crew would have to manually read over 4,200 meters and also be responsible for manually disconnecting/reconnecting customers. These substantial meter reading costs were one of the reasons that the current automated meter reading system was implemented.

Option 3: Install Current Generation 2 Way Metering in Larger Communities
Estimated Costs: \$3,044,000

In 2016 NTPC initiated a pilot project in Jean Marie River to evaluate a 2-way metering system called Gridstream RF which is provided by Landis + Gyr. Based on the success of this initial project NTPC is proposing to expand the use of this new meter technology.

This option would involve removing the current AMI meters in the larger communities NTPC serves including Dettah, Rae Edzo, Fort Resolution, Inuvik, Norman Wells, and Fort Simpson and installing the Gridstream RF 2-way meter system.

This technology revolves around 2 components. The physical infrastructure consists of meters, collectors, and routers and the software component which records and inquires on the data. A brief description of the new 2-way metering system and its key components are listed below:

- Meters – digital meters which provide remote connect/disconnect/limiting capabilities. Meters transmit an RF (radio frequency) signal for control and to report data.
- Routers - Receive the RF signal and repeat the signal to other routers or the collector.
- Collectors – receive the RF signal and send the data to the database.
- Command Center Software - controls meters, records meter information, reports on individual or grouped meter data and provides alerts on meter and distribution system disruptions.
- SmartWorks Software – provides meter management throughout the Corporation and an external customer portal of account meter readings and energy usage.



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

Based on the capabilities of the new system as outlined above, the Corporation and its customers would realize a number of soft benefits (benefits which offer clear value including financial savings but are not measurable at the outset). They include but are not limited to the following:

Customer Benefits

- Consistently accurate actual, not estimated, usage on power bills.
- Energy consumption information available through portal.
- Can assist customers in demand side management.
- In home electricity monitoring devices are available.
- Better move in/move out experience.
- Beyond the meter devices available to monitor and control household devices.

Customer Service and Billings Benefits

- Accelerates billing process and accelerates payment receipt reducing working capital.
- Better, more informed response to billing inquiries.
- Reduces steps required to process service orders.
- Allows for easier and efficient management of collection process.
- Identifies energy theft and meter tampering.
- Allows for 3rd party value added services such as water meter reading.

Operations Benefits

- Eliminates the time and physical risks of manual reading.
- Local operators are separated from collection disconnect/limiting conflicts.
- Reduces meter access issues.
- Provides accurate geographical display of meter location.
- Reports on self-generation.

Transmission & Distribution Benefits

- Provides detailed information for distribution load management.
- Allows for immediate outage detection and locating.
- Data available and reports produced for power quality / voltage monitoring.
- Facilitates system diagnostics and reporting.

Asset Management and Engineering Benefits

- Assists with community load profiling and forecasting

By selecting this option the existing automatic meters in the larger communities would be replaced which would resolve the issue of failing meters and unsupported infrastructure. The soft benefits outlined above would only apply to the larger NTPC communities. There will also be a reduction in meter re-reading and connect/disconnect labour time.



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

The cost to implement the new meter system would be \$2.958 M for the initial implementation and \$0.060M per year in annual software costs. The labour savings from the elimination of meter re-reads and meter connects/disconnects would be approximately \$0.055M per year.

Utilizing these costs a present value (PV) analysis was completed (Table 2) to estimate the total lifecycle cost of using the new intelligent meters. To calculate the Lifetime Labor Meter Savings attributed to the elimination of meter re-reading and connects/disconnects it was assumed they start in the first year and continue over 20 years as the meters are expected to last 20 years. It was also assumed that the labor cost savings would increase by 2% each year starting in year 4 of the 20 year evaluation period.

To calculate the Lifetime Software Cost Estimate it was also assumed the cost would be \$60,000 per year and would increase each year by 2% each year starting in year 2 of the 20 year evaluation period.

These lifetime costs estimates were then discounted at NTPC's current overall return on Ratebase, 6.88%. The total cost of this option would include the present value of the software, the labor meter savings and the initial cost capital costs of implementing the meters in the larger communities. The total estimated cost for this option is \$3.044M.

Table 2 – Project Cost Estimate – Current 2 Way Meters – Large Communities

Project Characteristics	Base Estimate
NTPC Return Required	6.88%
Expected Life New Meters (Years)	20
Lifetime Software Costs Estimate (\$000)	\$1,458
Lifetime Labour Meter Savings (\$000)	(\$1,288)
PV Intelligent Meter Capital Cost (\$000) [A]	\$2,958
PV Lifetime Software Costs Estimate [B]	\$747
PV Lifetime Labour Meter Savings (\$000) [C]	(\$661)
PV Total Project Cost (\$000) [D = A + B + C]	\$3,044

Option 4: Install Current Generation 2 Way Metering in All Communities except Fort Smith and Jean Marie River

Estimated Costs: \$4,333,000

This option is similar to option 3 and would involve removing the current AMI meters in the larger communities, removing the standard meters in the smaller communities and replacing them all with the Gridstream RF 2-way meter system. Please note Jean Marie River and Fort Smith would not



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

be included. Jean Marie River was used as a test community for these new meters. For the community of Fort Smith a separate case has been prepared.

The soft benefits outlined in option 3 would apply to all NTPC communities. In terms of costs to implement the new meter system, it would be \$4.247M for the initial implementation and \$0.060M per year in annual software costs (same as option 3). The labour savings would be the same as option 3 and would come from the elimination of meter re-reads and meter connects/disconnects in the larger communities. This would be approximately \$0.055M per year. No labour savings is anticipated in the smaller communities as there would be no reduction in the hours of the plant superintendents.

Utilizing these costs a present value (PV) analysis was completed (Table 2) to estimate the total lifecycle cost of using the new intelligent meters. To calculate the Lifetime Labor Meter Savings attributed to the elimination of meter re-reading and connects/disconnects it was assumed they start in the first year and continue over 20 years as the meters are expected to last 20 years. It was also assumed that the labor cost savings would increase by 2% each year starting in year 4 of the 20 year evaluation period.

To calculate the Lifetime Software Cost Estimate it was also assumed the cost would be \$60,000 per year and would increase each year by 2% each year starting in year 2 of the 20 year evaluation period.

These lifetime costs estimates were then discounted at NTPC's current overall return on Ratebase, 6.88%. The total cost of this option would include the present value of the software, the labor meter savings and the initial cost capital costs of implementing the meters in the larger communities. The total estimated cost for this option is \$4.333M.

Table 3 – Project Cost Estimate – Current 2 Way Meters – All Communities

Project Characteristics	Base Estimate
NTPC Return Required	6.88%
Expected Life New Meters (Years)	20
Lifetime Software Costs Estimate (\$000)	\$1,458
Lifetime Labour Meter Savings (\$000)	(\$1,288)
PV Intelligent Meter Capital Cost (\$000) [A]	\$4,247
PV Lifetime Software Costs Estimate [B]	\$747
PV Lifetime Labour Meter Savings (\$000) [C]	(\$661)
PV Total Project Cost (\$000) [D = A + B + C]	\$4,333



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

COST ESTIMATES

Table 4 – Budget Estimates

Description	2017/18	2018/19	2019/20	2020/21
Payroll Regular	82,000	82,000	82,000	82,000
Payroll Fringe Benefits	29,000	29,000	29,000	29,000
Meters	497,500	497,500	497,000	497,000
Computer Software	126,500	126,500	126,500	126,500
Contingency	166,000	166,000	165,500	165,500
Total Base Project Estimate	\$901,000	\$901,000	\$900,000	\$900,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$901,000	\$0	\$161,500	\$1,062,500
2018/19	\$901,000	\$0	\$161,500	\$1,062,500
2019/20	\$900,000	\$0	\$161,000	\$1,061,000
2020/21	\$900,000	\$0	\$161,000	\$1,061,000
Total Cost				\$4,247,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 21 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$4.247M
- Amortization rate of 4.73%
- Return on Ratebase of 6.88%
- Allocation of costs to entire region



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

Given the above assumptions, the average rate impact of the project for NTPC's customers is estimated at 0.471%. The sensitivity analysis in Table 5 shows the rate impacts of various cost scenarios.

Table 5 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$4,247	\$5,309	\$6,371	\$8,494
Amortization Period (Approx. Year)	21	21	21	21
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
Software License (\$000)	\$60	\$60	\$60	\$60
Amortization Expense (\$000)	\$201	\$251	\$301	\$402
Return on Ratebase (\$000)	\$292	\$365	\$438	\$584
Sub-Total: Revenue Requirement Increase (\$000)	\$553	\$676	\$800	\$1,046
Less: Estimated O&M Savings (\$000)	\$55	\$55	\$55	\$55
Total Revenue Requirement Impact (\$000)	\$498	\$621	\$745	\$991
Total Community Revenue Requirement (\$000)	\$105,840	\$105,840	\$105,840	\$105,840
Average % Rate Increase	0.471%	0.587%	0.704%	0.936%

SUMMARY OF BUSINESS CASE RATIONALE

The current automatic meter reading system in the larger communities NTPC serves is starting to fail. The current technology is no longer supported, and no replacement meters are available. As these meters fail it will cause the corporation to lose revenue despite providing power service to customers. This is not sustainable and a mass meter change is required in the near term.

NTPC has thoroughly evaluated its options. One of the options that have been pursued is the use of intelligent 2-way meter technology. NTPC has tested the Gridstream RF 2-way meter system in Jean Marie River and had very positive results. These meters would yield a significant number of benefits to customer and to NTPC's internal operations including reducing potential staff/customer



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

conflicts, improved response to outages, real-time data for process improvement and operational decision making.

The Corporation has also evaluated reverting back to standard meters in the larger communities. This would come with considerable labor costs as the line crew would have to manually read over 4,200 meters. On a purely financial basis the two options cost virtually the same. Reverting to standard meters would cost approximately \$3.3 M vs. \$3.0 M for the implementation of the new meters. The new meters would provide considerable soft benefits with a significantly improved customer experience, and improvements to internal process at the Corporation.

Given the considerable benefits to customers and the internal benefits the new meters would provide the Corporation has also evaluated using these meters for all customers. While there is no purely financial basis to implement these new meters for all customers, having a consistent customer experience and standardized metering approach would yield significant benefits for all stakeholders.

RECOMMENDATION

The Corporation recommends proceeding with the installation of the Gridstream RF two-way metering system in all the communities it serves as outlined in option 4. This new system will provide an improved customer experience. It will also provide benefits to day-to-day operations including reducing potential staff/customer conflicts, improved response to outages, real-time data for operational decision making. The total costs to complete the project are estimated to be \$4.247M.



Northwest Territories Power Corporation
Business Case
IMH Metering Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on pages 3, 5, 6, 8.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Inuvik K-Plant Combustion Air Upgrade

NEED FOR PROJECT

The Corporation proposes to undertake a project to upgrade the ventilation system in the Inuvik K-Plant by replacing the air handling unit (AHU) with a new higher capacity unit.

The Inuvik power plant was converted to natural gas over 15 years ago with the installation of two natural gas generator sets (gensets). A third natural gas genset was subsequently added and one of the gensets was converted to diesel, giving the plant the ability to generate electricity using two different fuel sources. However, the plant ventilation system was never upgraded to accommodate the plant modifications to add the third genset and convert the natural gas generator to diesel.

The main problems related to the current ventilation system are as follows:

- Make-up Air Unit not supplying sufficient air for the gensets, resulting in negative pressures inside the plant.
- The current ventilation system does not provide a sufficient supply of combustion air for the engines.
- The opening of doors in winter allows snow to enter the plant and causes instability of engines due to the large influx of cold air.
- Airflow in plant not sufficient enough to provide proper cooling around the engines in summer months.
- The power plant has elevated air temperatures in the summer season as the plant is not cooling properly, requiring the plant to operate with the overhead doors open, which allows dust to enter the plant.
- Inadequate temperature sensing for the auxiliary ventilation units.
- Temperature controls for the plant not properly synchronized, with the plant heating system trying to heat plant while ventilation system trying to cool plant.
- The original design may not be adequate for increased capacity and load in the plant.

These issues negatively impact the performance of the K-Plant and creating undesirable working conditions for company staff and contractors. The generators are not operating at peak performance and generation efficiency is negatively affected.

BACKGROUND

The existing ventilation system in the Inuvik K-Plant was designed in 1999 for the installation of the G11 and G12 natural gas generator sets (gensets). They had a combined electrical capacity of 4,900 kW and were fueled with non-scented natural gas.

The plant is heated using perimeter warm air heating provided by unit heaters fed by the plant heat recovery system. Combustion air is provided by a central Make-up Air Unit which also warms the air as it enters the plant.



Northwest Territories Power Corporation
Business Case
Inuvik K-Plant Combustion Air Upgrade

In 2005, the plant was modified by adding a third natural gas generator set (G10) rated at 2,800 kW. Subsequently, the G11 natural gas generator was converted to diesel. The ventilation system was not upgraded to accommodate the third genset addition or the diesel conversion modification.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option will not help in efforts to improve the reliability of this plant. Continued operation of the plant at negative air pressures or with large overhead doors open results in the influx of dust in the summer and cold air and snow in the winter. This can result in higher maintenance costs and degraded building performance. The operation of the plant at negative pressures reduces the fuel efficiency and stability of the engines.

Option 2: Combustion Air Upgrade

Estimated Costs: \$718,500

This option entails removing the existing AHU and main ducting in the Inuvik K-Plant, and replacing them with a new higher capacity AHU and ducting, as well as installing auxiliary ventilation fans and associated equipment.

The implementation of this option will provide the following key benefits to the Corporation and its customers:

- Improved reliability of K-Plant gas operations with the generators capable of running at full capacity. The operating conditions for the engines will be greatly improved resulting in less engine wear and longer engine life, which is expected to result in reduced maintenance costs over the generators life cycle.
- Potential improvement in fuel efficiency as a result of better engine combustion and cooling, as well as reduced exhaust emissions.
- Improved working environment in K-Plant for the Corporations staff and contractors.
- Improved confidence in plant reliability, potentially reducing the dependence on the diesel generation plant.



Northwest Territories Power Corporation
Business Case
Inuvik K-Plant Combustion Air Upgrade

COST ESTIMATES

Table 1 - Budget Estimates

Description	2017/18
Payroll Regular - CWIP	21,000
Payroll Regular O/T	3,000
Fringe Benefits	8,000
Consultants Lump Sum	63,000
Contractors Lump Sum	198,000
Transportation	10,000
Accommodation	1,500
Meals	500
Freight	6,000
AHU, Ducting & Other	84,000
VFD Equipment	7,000
Aux Ventilation Equipment	58,000
PLC I/O Equipment	2,000
Wire & Cable	7,000
Contingency	140,000
Total	\$609,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$609,000	-	\$109,500	\$718,500
Total Project Cost				\$718,500



Northwest Territories Power Corporation
Business Case
Inuvik K-Plant Combustion Air Upgrade

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.719M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.11%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$719	\$898	\$1,078	\$1,437
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$29	\$36	\$44	\$58
Return on Ratebase (\$000)	\$35	\$44	\$52	\$70
Sub-Total: Revenue Requirement Increase (\$000)	\$64	\$80	\$96	\$128
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$64	\$80	\$96	\$128
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.11%	0.14%	0.16%	0.22%



Northwest Territories Power Corporation
Business Case
Inuvik K-Plant Combustion Air Upgrade

SUMMARY OF BUSINESS CASE RATIONALE

The current ventilation system in the Inuvik K-Plant is inadequate and needs to be upgraded. The system was only designed to accommodate two natural gas gensets. A third genset was added in 2005 and the existing G11 genset was converted to diesel. The plant ventilation was never upgraded to accommodate these plant modifications, resulting in a number of plant issues that need to be rectified. Installing a new higher capacity AHU unit and auxiliary ventilation fans will allow the gensets to operate at peak output and efficiency, with potential improvements in plant reliability, reduced fuel costs, lower maintenance costs and reduced exhaust emissions. It will also improve the working conditions at the plant, which can positively impact staff morale and productivity.

RECOMMENDATION

The Corporation recommends upgrading the ventilation system in the Inuvik K-Plant as outlined in option 2. The total costs to complete the project are estimated to be \$0.719M.



Northwest Territories Power Corporation
Business Case
Inuvik K-Plant Combustion Air Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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2017/18 Business Cases



Northwest Territories Power Corporation
Business Case
Inuvik – New Exhaust Gas Recovery Unit (EGRU)

NEED FOR PROJECT

NTPC is proposing to undertake a project to install a fire tube gas-to-liquid Exhaust Gas Recovery Unit (EGRU) to the heat recovery systems on the G10 natural gas generating unit. The project will also consist of various changes and upgrades to G10's jacket water, oil cooler and after cooler systems, with the additional major equipment including heat exchangers and a new single core radiator, all of which are PLC controlled. The installation and upgrades will increase the residual heating supply to the Medium Temperature (MT) circuit at the Inuvik K-Plant's power station.

The Inuvik MT and Low Temperature (LT) Heat Distribution System are presently experiencing large heating load demand from the new Inuvik warehouse facility, vaporizer heat required for the LNG facility and Inuvik Water Treatment facility (this facility receives heat solely from the LT System). The backup boilers are required to run at near full operational capacity to meet the required demand of the MT System. The backup boilers operate on natural gas and they generate the heat required to operate the LNG facility. This process is not efficient with substantial energy losses arising from the burning of natural gas to generate medium temperature heat, which is in turn used to produce natural gas. Consequently, a large amount of natural gas is used to create MT heat thereby resulting in higher operating costs and reducing the power plant's generation efficiency. The EGRU produces heat much more efficiently than the backup boilers, and as a result, there is a requirement to upgrade the heat recovery system on the G10 generator to include an EGRU.

BACKGROUND

The Inuvik G10 unit is a Wartsila 18V220SG natural gas-fueled generator set rated at 2800 kW. The existing engine cooling system is dual circuit, dual core, with separate jacket water and aftercooler-oil cooler circuits circulating through a dual core radiator. The existing installation on G10 only includes heat recovery from the jacket water cooling system. The jacket water heat recovery system supplies heat to the Inuvik Medium Temperature (MT) Distribution System. The MT System is currently comprised of jacket water and exhaust gas heat from G11 and G12, and only jacket water heat from G10. The MT System provides comfort heat to the K-Plant, EMD Plant, new Warehouse and heat to the LNG Vaporizer.

There are two backup natural gas fired boilers installed in the power plant that provide additional heating supply when needed and all the heating requirements to the MT System when gensets are not operating. Since the addition of the new warehouse and LNG facility, the backup boilers have been running nearly full time providing additional heating demand when the LNG gensets (G12 and G10) are online. Low Temperature (LT) heat is currently recovered from the aftercooler-oil cooler circuits of G11 and G12. The LT system supplies heat to the Town of Inuvik's Water Treatment facility as well as the K-Plant and EMD Plant Air Handling Units (genset combustion air).

The heating load increase in the MT Heat Distribution Systems (New Inuvik warehouse, vaporizer heat for the LNG facility) has resulted in the requirement to upgrade the heat recovery system on G10 to include Exhaust Gas Heat Recovery as only G12 and G10 consume the more economical



Northwest Territories Power Corporation
Business Case
Inuvik – New Exhaust Gas Recovery Unit (EGRU)

LNG. The LNG backup boilers and G12 and G10 do not have LNG consumption meters installed to meter the amount of LNG being consumed. The 2017 Capital Program has identified as a separate project the installation of gas consumption meters on the LNG backup boilers and G10 and G12.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The "do nothing" option does not allow the G10 unit (operating on the more economical fuel source of LNG) to provide additional heating to supply the heating demands of the MT and LT systems. The backup natural gas boilers will be required to operate nearly 100% of the time to meet the additional heating demand thereby reducing the life of the boilers and increasing maintenance costs.

Option 2: Install EGRU unit and upgrade jacket water and aftercooler-oil cooler system Estimated Costs: \$1,773,000

This option includes the installation of a new EGRU unit on the G10 generator unit with upgrades to G10's jacket water and aftercooler-oil cooler system supplying additional heat to both the MT and LT systems. The additional heating supply with the G10 unit will meet all the heating demands of the power plant while the G11/G12 units are simultaneously meeting the plant's electrical generation requirements. The estimated total cost is \$1.7M.

The benefits of option 2 are summarized as follows:

- Increased residual heating supply to the MT Heat Distribution System to meet heating load requirements.
- Allows the backup boilers to only operate when the G10, G11 or G12 units are offline extending the life of the boilers and reduces maintenance costs.

Option 3: Install EGRU unit only Estimated Costs: \$1,300,000

Option 3 includes the installation of a new EGRU unit on the G10 generator but does not allow for upgrades to the jacket water and aftercooler-oil cooler system on G10. This option will only supply additional heat to the MT system but will not address the heating demand requirements of the LT system. This option has an estimated total cost of \$1.3M.



Northwest Territories Power Corporation
Business Case
Inuvik – New Exhaust Gas Recovery Unit (EGRU)

COST ESTIMATES

Table 1 – Budget Estimates

Design

Description	2014/15	2015/16
Payroll Regular	-	16,000
Payroll O/T	-	2,000
Payroll Fringe Benefits	-	5,000
Consultants Lump Sum	44,000	64,000
Transportation	-	2,500
Accommodation	-	4,500
Meals	-	2,000
Total Base Project Estimate	\$44,000	\$96,000

Construction

Description	2014/15	2015/16
Payroll Regular	-	20,000
Payroll Fringe Benefits	-	7,000
Consultants Lump Sum	-	13,000
Contractors Lump Sum	-	590,000
Transportation	-	10,000
Accommodation	-	10,000
Meals	-	4,000
Freight	-	30,000
NTPC Purchased Materials	-	350,000
Contingency	-	279,000
Total Base Project Estimate	\$0	\$1,313,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2014/15	\$44,000	\$500	\$9,000	\$53,500
2015/16	\$1,409,000	\$500	\$310,000	\$1,719,500
Total				\$1,773,000



Northwest Territories Power Corporation
Business Case
Inuvik – New Exhaust Gas Recovery Unit (EGRU)

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$1.773M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.270%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$1,773	\$2,216	\$2,660	\$3,546
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$72	\$90	\$107	\$143
Return on Ratebase (\$000)	\$86	\$108	\$130	\$173
Sub-Total: Revenue Requirement Increase (\$000)	\$158	\$197	\$237	\$316
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$158	\$197	\$237	\$316
Total Community Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.270%	0.338%	0.406%	0.541%



Northwest Territories Power Corporation
Business Case
Inuvik – New Exhaust Gas Recovery Unit (EGRU)

SUMMARY OF BUSINESS CASE RATIONALE

The Inuvik MT and LT Heat Distribution Systems are experiencing a high level of heating demand from NTPC and municipal facilities in the community. The present use of backup boilers to provide residual heat is very inefficient. Consequently, the Corporation must upgrade the heat recovery system on the G10 generator to include an EGRU to implement a more efficient heating system to reduce potential future maintenance costs.

RECOMMENDATION

It is recommended the Corporation proceed with the proposed project as outlined under option 2. This option meets the needs of the heating circuits for the MT System, and the backup boilers will only operate when the G10, G11 and G12 units are offline. The total costs to complete the project are estimated to be \$1.773M.



Northwest Territories Power Corporation
Business Case
Inuvik – New Exhaust Gas Recovery Unit (EGRU)

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

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Northwest Territories Power Corporation Business Case Jackfish Control System Upgrades

NEED FOR PROJECT

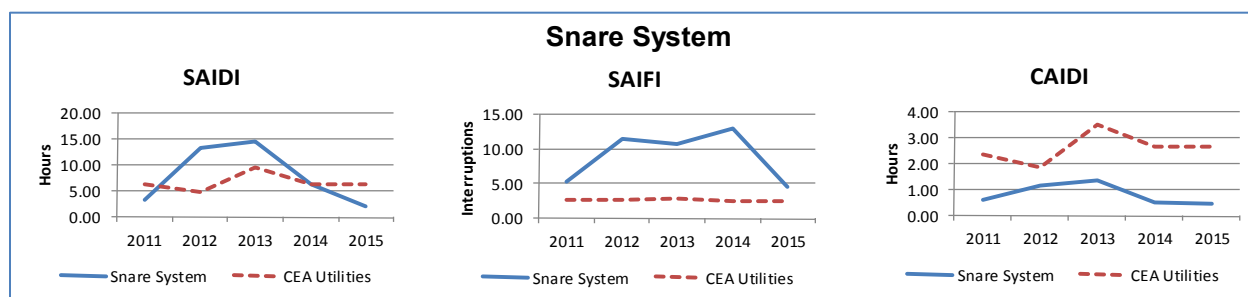
The Corporation is proposing to undertake a project to address control system problems that are being experienced at the Jackfish diesel plants. When an outage occurs on the North Slave system (Yellowknife), operations are forced to work around the control system problems. The result is that it takes much longer than it should to switch over to the backup system (Jackfish), extending the length of customer outages.

BACKGROUND

Jackfish has three power plants, K-Plant, EMD-plant and Cat-Plant. The EMD Plant was built in 1974 and extended in 1988. It contains four generators (gensets); two E-series gensets rated at 2,500 kW each and two F-series gensets rated at 2,850 kW each. The CAT plant, built in 1993, contains two CAT 3612 gensets rated at 3,300 kW. Since the early 2000s, after the closing of mines in Yellowknife, Jackfish has been acting as backup generation for the Hydro system.

Over the last two years the North Slave system was experiencing low water, which resulted in reduced Hydro generation capacity and the continuous running of the Jackfish diesel plant. Since Jackfish has been running continuously, many of the control system problems have been avoided. This made for a very stable system. NTPC and its customers enjoyed high levels of reliability.

Presented below are some common reliability indicators showing how the North Slave system (Snare) compares with other CEA (Canadian Electricity Association) utility systems over the last five years.



System Average Interruption Duration Index (SAIDI) - SAIDI is the average outage duration for each customer served.

System Average Interruption Frequency Index (SAIFI) - SAIFI is the average number of interruptions that a customer would experience.

Customer Average Interruption Duration Index (CAIDI) - CAIDI gives the average outage duration that any given customer would experience. CAIDI can also be viewed as the average restoration time. (SAIDI/SAIFI)

The Snare system is an islanded system and it is the sole provider of power for North Slave customers. If the system goes down this causes an outage. Other larger CEA markets such as Alberta have multiple generating plants running and more transmission capacity. If there is loss



Northwest Territories Power Corporation
Business Case
Jackfish Control System Upgrades

of a plant the others can seamlessly increase their output, and outages occur less frequently. This can be seen in the SAIFI statistics above. The frequency of outages also drives SAIDI higher, or number of hours of outage.

However the length of outage (CAIDI) is much lower on the North Slave system (Snare) compared to other CEA utilities. Power is able to be restored more quickly as a result of the extra capacity from the diesel based backup (Jackfish).

Reviewing the performance for North Slave (Snare) we see a significant improvement in all of the reliability indicators in 2014-2015. While there have been improvement initiatives that have taken place regarding reliability, this improvement was largely driven by the continuous use of Jackfish (due to low water). With Jackfish running continuously, many of the control system problems were avoided.

In spring of 2016, Hydro inflows appear to be returning to normal, which has allowed NTPC to supply customers with Hydro. It is expected that reliability will return to pre-2014 levels.

The purpose of the control system project at Jackfish is to reduce the time required to switch from hydro to the diesel backup. This would drive improvement in the already strong CAIDI (restoration time), on North Slave, and SAIDI (customer outage duration) statistics.

The specific control system issues the project would address include voltage regulation, governing control, PLC (Programmable Logic Controller) control and the SCADA (Supervisory Control and Data Acquisition) interface.

The existing voltage, governing and PLC control systems at Jackfish are of a late 1980s and early 1990s vintage and have reached end of life. The control systems consist of mismatched equipment with different levels of capability.

At the current time, the voltage regulation systems cannot be set to regulate voltage properly, which is causing units to trip off (shut down) under certain conditions. The governing control is awkward to use, is not responding to commands and occasionally changing states on its own. The PLC and SCADA systems are difficult to control and are frequented by glitches.

The proposed control system project would begin to address these challenges by having an expert assess the current equipment and make recommendations so the current equipment performs as well as possible. It would also include design work for the replacement of the current voltage regulation and governing equipment.



Northwest Territories Power Corporation
Business Case
Jackfish Control System Upgrades

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The current system controls at Jackfish would remain in place and reliability would be expected to return to pre-2014 levels.

Option 2: Jackfish Control System Upgrade Estimated Cost: \$880,000

This option consists of two elements. They include the updating of the control settings on current equipment and the design of a new control system for Jackfish.

- Current equipment control settings – A control system expert would assess the existing equipment. This expert would then suggest the optimal settings and programming. The goal would be to get the best possible results from the current equipment.
- New control system design – This would involve the design of replacement voltage regulation and governing equipment for Jackfish

The benefits of completing this project would be that the current equipment settings would be set so as to get the best possible performance from the control systems. This will drive reductions in outage time and improve the reliability of the North Slave system.

The other deliverable from the project would be a design of replacement voltage regulation and governing equipment which can be used to provide a permanent fix to the control system problems at Jackfish. This would also contribute to reducing outage time and improving the reliability of the North Slave system over the longer term.

COST ESTIMATES

Table 1 – Budget Estimates

Design

Description	2016/17	2017/18
Payroll Regular	20,000	-
Payroll OT	2,000	-
Payroll Fringe	7,000	-
Consultants Lump Sum	89,000	-
Transportation	4,000	-
Accommodation	2,000	-
Meals	1,000	-
Contingency	25,000	-
Total	\$150,000	\$0



Northwest Territories Power Corporation
Business Case
Jackfish Control System Upgrades

Construction

Description	2016/17	2017/18
Payroll Regular	-	51,000
Payroll OT	-	6,000
Payroll Fringe	-	18,000
Consultants Lump Sum	74,000	95,000
Contractors Lump Sum	-	105,000
Transportation	-	6,000
Accommodation	-	4,000
Meals	-	5,000
Freight	-	10,000
Automation/Supervisory System (Hydro)	-	51,000
Automation/Supervisory System (Jackfish)	-	60,000
Contingency	15,000	82,000
Total	\$89,000	\$493,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2016/17	\$239,000	\$8,000	\$43,000	\$290,000
2017/18	\$493,000	\$8,000	\$89,000	\$590,000
Total				\$880,000



Northwest Territories Power Corporation
Business Case
Jackfish Control System Upgrades

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates for Diesel Plants. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.880M.
- Amortization rate of 4.04%.
- Return on Ratebase of 7.18%.
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.266%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$880	\$1,100	\$1,320	\$1,760
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$36	\$44	\$53	\$71
Return on Ratebase (\$000)	\$63	\$79	\$95	\$126
Sub-Total: Revenue Requirement Increase (\$000)	\$99	\$123	\$148	\$197
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$99	\$123	\$148	\$197
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.266%	0.332%	0.398%	0.531%



Northwest Territories Power Corporation
Business Case
Jackfish Control System Upgrades

SUMMARY OF BUSINESS CASE RATIONALE

In the last few years, reliability on the North Slave system has improved significantly. This is largely due to the continuous use of Jackfish diesel generation due to low water. With Jackfish running continuously, many of the control system problems at the plant have been avoided. In 2016, Hydro inflows appear to be returning to normal, which will allow NTPC to supply customers with hydro power. It is expected that with some action taken reliability on the North Slave system will return to pre-2014 levels.

When an outage occurs on the North Slave system (Yellowknife) operations is normally forced to work around the control system problems present at the Jackfish plant. The result is that it takes much longer than it should to switch over to Jackfish (backup system) extending the length of customer outages.

There are a number of issues with the current control system at Jackfish including voltage regulation, governing control, PLC (Programmable Logic Controller) control and the SCADA (Supervisory Control and Data Acquisition) interface. The current equipment is over twenty years old and at the end of its useful life.

The Corporation is proposing to complete a project that addresses these problems. There are two elements. The first element consists of updating the control settings on the current equipment. An expert would assess the equipment and make recommendations to get the best possible performance from the existing equipment. The second element is the design of replacement voltage regulation and governing equipment for Jackfish.

Depending upon the design recommendations made at that time and the estimated cost NTPC will file if necessary a permit application with the PUB related to the replacement of the voltage regulation and governing equipment.

RECOMMENDATION

It is recommended NTPC proceed with the proposed project as outlined under option 2. This project will further increase the reliability of the North Slave System. The total cost to complete the project is estimated at \$0.880M.



Northwest Territories Power Corporation
Business Case
Jackfish Control System Upgrades

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 5.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Jackfish K-Plant Cooling System Upgrade

NEED FOR PROJECT / BACKGROUND

NTPC is proposing to undertake a project to replace all of the water cooling piping in the Jackfish K-Plant in Yellowknife. The diesel generators in this plant have been de-rated because they overheat due to restriction in the cooling water pipes, which are approaching the end of their useful life. The majority of the piping is original 1971 vintage, with some newer pipes installed in 1988. There are two raw water pumps for each generating unit. It has become necessary to run both pumps for a unit at one time in order to prevent overheating, especially as temperatures rise in late spring and summer. The pipes are badly corroded and restricted due to the corrosion, with many of the valves leaking internally.

Replacing the water cooling pipes will enable the diesel generators to operate at higher loads, thereby increasing the available capacity of the plant. Plant reliability will be enhanced as engine overheating will no longer be a problem. In addition, reducing engine temperatures may improve the lifespan of various engine components (e.g., cylinder heads, turbos).

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The continuation of the status quo and not upgrading the K-Plant cooling system will result in the continued deterioration of the plant's cooling system. Maintenance costs are expected to rise as the problem with the pipes and leaking valves worsen. The engines will remain de-rated and prevented from operating at peak output. The do nothing option is not viable as the pipes have reached the end of their useful life and need to be replaced.

Option 2: Upgrade K-Plant Cooling System

Estimated Costs: \$791,500

This option entails replacing all of the cooling water piping in the Jackfish K-Plant. This will also require the cleaning and flushing of the coolers and heat exchangers. This option will provide the following key benefits to the Corporation:

- **Plant Reliability:** The upgrade of the cooling system will increase the reliability of the Jackfish K-Plant. The diesel generators can be run at full capacity without overheating, which increases the total diesel generation output of the plant and allows the Corporation to better meet the load demands of its customers.
- **Engine Reliability:** The upgrade will improve the cooling system of the engine and is expected to extend the engine's useful life. Improved cooling results in the engine operating at lower temperatures and reduces abnormal engine wear from elevated operating temperatures. This could potentially reduce the engine's maintenance costs over its lifecycle as parts last longer and do not need to be replaced as frequently.



Northwest Territories Power Corporation
Business Case
Jackfish K-Plant Cooling System Upgrade

COST ESTIMATES

Table 1 – Budget Estimates

Design

Description	2017/18
Payroll Regular	17,000
Payroll Overtime	1,000
Payroll Fringe Benefits	6,000
Consultants Lump Sum	17,000
Transportation	500
Accommodation	1,500
Meals	500
Contingency	13,000
Total	\$56,500

Construction

Description	2018/19
Payroll Regular	35,000
Payroll Overtime	47,000
Fringe Benefits	12,000
Contractors Lump Sum	210,000
Transportation	2,000
Accommodation	18,000
Meals	7,000
Equipment Rental	19,000
Freight	20,000
Pipe	26,000
Elbows, tees, reducers	7,000
Gate Valves	27,000
Coolers	40,000
Contingency	141,000
Total	\$611,000



Northwest Territories Power Corporation
Business Case
Jackfish K-Plant Cooling System Upgrade

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$56,500	\$1,900	\$10,200	\$68,600
2018/19	\$611,000	\$1,900	\$110,000	\$722,900
Total Project Cost				\$791,500

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.792M
- Amortization rate of 4.04%
- Return on Ratebase of 7.18%
- Allocation of costs to Snare Zone

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.152%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
Jackfish K-Plant Cooling System Upgrade

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$792	\$989	\$1,187	\$1,583
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$32	\$40	\$48	\$64
Return on Ratebase (\$000)	\$57	\$71	\$85	\$114
Sub-Total: Revenue Requirement Increase (\$000)	\$89	\$111	\$133	\$178
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$89	\$111	\$133	\$178
Total Community Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.152%	0.190%	0.228%	0.304%

SUMMARY OF BUSINESS CASE RATIONALE

The water cooling piping in the Jackfish K-Plant in Yellowknife has reached the end of its useful life and need to be replaced. The pipes are badly corroded, with leaking valves and internal restrictions limiting the flow of water through the pipes. The piping issues limit the ability of the cooling system to properly cool the diesel generators, forcing the plant operators to de-rate the gensets and operate the units below their peak output. Upgrading the cooling system will allow the gensets to operate at peak output, which will increase total plant diesel generation output capacity and improve overall plant reliability. The cooling system upgrade will also provide better cooling to the gensets and prevent overheating, which is expected to improve engine reliability and reduce maintenance costs over time.

RECOMMENDATION

The Corporation recommends proceeding with the upgrade of the Jackfish K-Plant cooling system as outlined in option 2. The total costs to complete the project are estimated to be \$0.792M.



Northwest Territories Power Corporation
Business Case
Jackfish K-Plant Cooling System Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
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Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Jackfish T4 Transformer Upgrade

NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to complete a refurbishment on the T4 transformer at its Jackfish substation in Yellowknife. The T4 transformer was originally installed in 1976 and in recent years began to exhibit operational issues. Consequently, a decision was made to purchase a new transformer to replace the T4 unit. A new transformer, T19 was purchased and the T4 unit was taken out of service.

This project would entail refurbishing the T4 unit and using it as a standby transformer for the newer T19 transformer. The T19 unit is a critical component of the Power supply system. If this transformer failed, the 115 kV transmission line that transmits 25 kW power from the Snare generation system to Yellowknife will remain disconnected from the Jackfish substation and Yellowknife will suffer a 25 kW hydro power deficit.

A transformer is also a long lead-time item, requiring up to five months, to procure. The installation and commissioning would require an additional month. Therefore, if the T19 transformer suddenly fails, plant operators must use diesel generation to supply power to Yellowknife until a new transformer is installed, which would cost the Corporation millions of dollars in diesel fuel expense.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The status quo would prevail and there would be no backup transformer available if T19 were to fail. A transformer failure at Jackfish could cause a long-term loss of hydro power while another transformer is acquired. This option is not viable given the long lead time required to purchase and install a new transformer and the resulting large increase in the Corporation's annual diesel expense.

Option 2: Refurbish T4 Transformer

Estimated Costs: \$656,000

This option would consist of refurbishing T4 and then putting the unit back into service. The unit would be utilized in a standby capacity only. The project would be implemented over a two year period as outlined below:

- 2017 – Install new tap changer (voltage regulation) parts.
- 2018 – Transport the transformer to a facility for refurbishing, which includes having its core and coils removed, cleaned and inspected. The unit would then be re-insulated and tested. Assuming satisfactory test results, the transformer would be shipped back to Yellowknife and put into service.



Northwest Territories Power Corporation
Business Case
Jackfish T4 Transformer Upgrade

By completing the refurbishment of T4 transformer, the Corporation would have access to a backup transformer, which could be used if T19 transformer failed. This would improve the reliability of the North Slave system (Yellowknife) as the T4 could be brought online immediately in the event of a failure of T19.

Option 3: Purchase New T4 Transformer
Estimated Costs: \$2,000,000

The option would consist of purchasing a new T4 transformer to be used as a backup for the current T19 transformer. Purchasing a new transformer has a significantly greater capital cost than refurbishing the existing unit; however, the new unit would have a longer useful life than the refurbished unit and come with a warranty from the manufacturer.

COST ESTIMATES

Table 1 – Budget Estimates

Description	2016/17	2017/18
Payroll Regular	14,000	-
Fringe Benefits	5,000	-
Contractors Lump Sum	40,000	400,000
Contingency	15,000	78,000
Total	\$74,000	\$478,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2016/17	\$74,000	\$2,000	\$14,000	\$90,000
2017/18	\$478,000	\$2,000	\$86,000	\$566,000
Total Project Cost				\$656,000



Northwest Territories Power Corporation
Business Case
Jackfish T4 Transformer Upgrade

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 47 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.656M
- Amortization rate of 2.15%
- Return on Ratebase of 7.18%
- Allocation of costs to Snare Zone

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.165%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$656	\$820	\$984	\$1,312
Amortization Period (Approx. Year)	47	47	47	47
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$14.10	\$17.63	\$21.16	\$28.21
Return on Ratebase (\$000)	\$47.10	\$58.88	\$70.65	\$94.20
Sub-Total: Revenue Requirement Increase (\$000)	\$61.20	\$76.51	\$91.81	\$122.41
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$61.20	\$76.51	\$91.81	\$122.41
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.165%	0.206%	0.247%	0.329%



Northwest Territories Power Corporation
Business Case
Jackfish T4 Transformer Upgrade

SUMMARY OF BUSINESS CASE RATIONALE

The T4 transformer was installed at the Jackfish transmission plant over 39 years ago and is near the end of its useful life. T4 unit is no longer in service due to previous operational issues. The Corporation is proposing to refurbish the unit and use it as a standby transformer for the T19 transformer presently in service. Transformers are long lead-time items requiring many months before they can be put into service. A transformer failure at Jackfish could result in an extended interruption in the delivery of hydro generation to customers in Yellowknife. This in turn could lead to a significant increase in diesel usage with negative environmental impacts and significant costs.

The completion of this refurbishment project would provide the Corporation with access to a backup transformer if T19 transformer failed, which would improve the reliability of the North Slave system (Yellowknife).

RECOMMENDATION

The Corporation recommends proceeding with the refurbishment of the T4 transformer as outlined in option 2. The total costs to complete the project are estimated to be \$0.656M.



Northwest Territories Power Corporation
Business Case
Jackfish T4 Transformer Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

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Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Nahanni Butte Fuel System Upgrade

NEED FOR PROJECT

The Corporation is proposing to install and commission a new fuel system for the Nahanni Butte plant. This would include replacement of the day tank, and the fuel piping and valves at the plant. The Corporation also proposes to replace the current 90,000 liter main fuel tank at the plant as it is over 40 years old.

BACKGROUND

The Nahanni Butte power plant has three diesel generators. These include:

- G1 - CAT 3304 (80kW)
- G2 - Detroit D4-71 (75kW)
- G3 - Isuzu (90kW)

The current fuel system at the plant, which provides the fuel to the run the generators, has the following deficiencies that need to be addressed:

- Indoor Piping – The current piping is no longer compliant with NTPC Piping and Valve Specifications and certain GNWT requirements.
- Tank level control system – No longer meets current NTPC standards. The fuel tank at the plant is at risk of overflowing, leading to a spill.
- Fuel pump controls - No longer meets the code requirements of the Fire Marshal
- Fuel cooling and filtration – The current system lacks adequate return fuel cooling and fuel filtration. It is not compliant with current NTPC best practice design, it inhibits the efficiency of the engines, and increases the time required for unplanned maintenance.
- Plant Configuration - The current fuel system setup restricts access to the G3 genset due to limited space within the plant making maintenance more difficult to complete

The 90,000 liter main fuel tank at the plant also requires replacement as it is 40 years old and has reached the end of its useful life.

The Corporation monitors regulatory requirements and incorporates these requirements into the 5 year Capital Program. This program replaces/upgrades assets as required to ensure NTPC meets existing regulatory codes. In addition, the Capital Program is updated as regulatory changes occur, ensuring the Corporation continues to meet regulatory requirements.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The current fuel system and main fuel tank at the plant are not compliant with certain NTPC corporate policies and regulatory codes, and doing nothing is not a viable option. A failure to



Northwest Territories Power Corporation
Business Case
Nahanni Butte Fuel System Upgrade

upgrade the current fuel system and replace the main tank, would pose unacceptable safety, reliability, and environmental risks.

Option 2: Fuel System Upgrade and Main Tank Replacement
Estimated Costs: \$905,000

This option consists of upgrading the current fuel system and replacing the main fuel tank at the Nahanni Butte plant. This project is part of a corporate initiative to upgrade the fuel tanks, piping, and related systems at diesel based plants. These upgrades will enhance plant safety, reliability and ensure compliance with current regulatory requirements. Consistent with this policy the proposed project consists of the following elements:

- Indoor Piping Upgrade - Fuel piping and valves upgraded to meet current NTPC piping and valve specifications.
- New Fuel System – This includes a new double-walled day tank, a new tank level control system, pumping system, water separator, fuel cooler and filters.
- Day Fuel Tank Housing - Day fuel tank to be housed in a new separate module beside the plant
- New Main Fuel Tank – Double-walled 90,000 liter fuel storage steel tank

By upgrading the current fuel system and replacing the main tank at the plant the Corporation would reduce risk in a number of key areas, particularly fuel spills and the associated consequences. Please see below:

- Environmental - Fuel spills could cause damage to the environment and are costly to remediate.
- Safety
 - Employees - In the event of a fuel spill staff could be exposed to dangerous fumes or have their skin exposed to the liquid and suffer injury. This risk would exist not only at the initial time of the spill but also throughout the time of the required cleanup.
 - Plant – A fuel spill along with a source of ignition could result in a fire. This could cause significant damage to the plant, and potentially significant injuries to staff.
- Reliability
 - Fuel spills – A fuel spill could result in plant shutdown to clean up the spill or if a fire were to occur damage the plant so extensively to make it no longer operational
 - Reduced downtime – The new fuel cooling and filtration system will reduce the time to complete unplanned maintenance on the fuel system. Also, the separate fuel housing makes accessing generators easier, reducing the time to complete repairs.



Northwest Territories Power Corporation
Business Case
Nahanni Butte Fuel System Upgrade

COST ESTIMATES

Table 1 – Budget Estimates

Design

Description	2017/18
Payroll Regular	24,000
Payroll Overtime	3,000
Payroll Fringe Benefits	8,000
Transportation	1,000
Accommodation	1,000
Contingency	11,000
Total Base Project Estimate	\$48,000

Construction

Description	2017/18
Payroll Regular	24,000
Payroll Overtime	6,000
Payroll Fringe Benefits	9,000
Contractors Lump Sum	346,000
Transportation	16,000
Accommodation	10,000
Meals	4,000
Equipment Rental	1,000
Freight	11,000
Fuel storage tank	110,000
Control panel	15,000
Contingency	167,000
Total Base Project Estimate	\$719,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$767,000	\$0	\$138,000	\$905,000



Northwest Territories Power Corporation
Business Case
Nahanni Butte Fuel System Upgrade

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.905M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.138%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$905	\$1,131	\$1,358	\$1,810
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$37	\$46	\$55	\$73
Return on Ratebase (\$000)	\$44	\$55	\$66	\$88
Sub-Total: Revenue Requirement Increase (\$000)	\$81	\$101	\$121	\$161
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$81	\$101	\$121	\$161
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.138%	0.173%	0.207%	0.276%



Northwest Territories Power Corporation
Business Case
Nahanni Butte Fuel System Upgrade

SUMMARY OF BUSINESS CASE RATIONALE

The current fuel system and main fuel tank at the Nahanni Butte plant is not compliant with certain NTPC corporate policies and regulatory codes. The current system poses unacceptable safety, reliability, and environmental risks.

As part of an overall program at NTPC to upgrade the fuel tanks, piping, and related systems at diesel based plants, the Corporation proposes to address these concerns with the installation and commissioning of a new fuel system and replacement of the main fuel tank.

The benefits realized by making these upgrades at the plant include reduced risk of fuel spills and the associated environmental and safety concerns, as well as reduced plant downtime. The new fuel cooling and filtration system will increase genset efficiency and be in line with NTPC's best practices and regulatory codes.

RECOMMENDATION

The Corporation recommends proceeding with the project as outlined in option 2. Upgrading the fuel system at the plant and replacing the main fuel tank will allow NTPC to meet its obligation to provide safe, reliable power to customer in an environmentally responsible manner. The total costs to complete the project are estimated to be \$0.905M.



Northwest Territories Power Corporation
Business Case
Nahanni Butte Fuel System Upgrade

Attachment A

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Northwest Territories Power Corporation
Business Case
Paulatuk New Living Accommodations

NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to acquire and install a trailer in Paulatuk to provide appropriate temporary accommodations for staff who service the local plant.

In 1976, a one bedroom trailer was installed for NTPC crews. After years of use, the trailer was in poor condition and in need of replacement. Subsequently, hotel accommodations became available in Paulatuk. Instead of replacing the trailer, a decision was made to utilize the local hotel rooms and abandon the trailer.

The hotel is quite small and only has six rooms available to accommodate its customers. Crews can book rooms in advance; however, in short notice situations, rooms may not be available for staff. All the rooms are shared accommodations resulting in staff frequently sharing a room with an unknown person.

Guest services at the hotel are also quite limited. Food is served at a fixed time with no options provided. There are no meal options at the hotel for staff who are working late or have food allergies.

The local plant has no temporary accommodations available. Paulatuk is a small community and the hotel is the only available local accommodations at present time.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

This option results in a continuation of the status quo and NTPC transient Paulatuk staff will continue to contend with health, safety and privacy concerns.

Option 2: Lease or Rent in Paulatuk

NTPC staff has investigated options for the rental or lease of suitable accommodations and have received no responses. Paulatuk is small community with a population of 313 and 98 total dwellings as of 2011 per Statistics Canada¹. The Hotel is the only facility with temporary accommodations available for company staff.

¹ Statistics Canada. 2012. *Paulatuk, Northwest Territories (Code 6101014) and Northwest Territories (Code 61) (table). Census Profile. 2011 Census.* Statistics Canada Catalogue no. 98-316-XWE. Ottawa. Released October 24, 2012. <http://www12.statcan.gc.ca/census-recensement/2011/dp-pd/prof/index.cfm?Lang=E> (accessed May 13, 2016).



Northwest Territories Power Corporation
Business Case
Paulatuk New Living Accommodations

Option 3: Acquire and Install Trailer

Estimated Costs: \$419,000

This option would involve the purchase of a two bedroom trailer, accessories such as furniture and appliances, and its installation in Paulatuk. The benefits of this option would include the following:

- Safety – When staff stay at the hotel, they frequently share rooms with unknown individuals some of whom have exhibited inappropriate behavior. Having a company trailer for staff reduces these types of risks.
- Reliability – Staff must frequently delay travel to Paulatuk if no rooms are available at the hotel. This results in delaying required maintenance, repairs, etc. These delays impact the reliability of the power system in Paulatuk. In addition, sharing rooms with others frequently results in interruptions to staff from other guests, which can impact staff work performance.

COST ESTIMATES

Table 1 – Budget Estimates

Description	2016/17	2017/18
Payroll Regular	-	4,000
Payroll Fringe Benefits	-	1,000
Contractors Lump Sum	-	22,000
Transportation	-	3,000
Accommodation	-	1,000
Freight	6,000	70,000
Building	167,000	11,000
Contingency	35,000	23,000
Total Base Project Estimate	\$208,000	\$135,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2016/17	\$208,000	\$7,000	\$38,000	\$253,000
2017/18	\$135,000	\$7,000	\$24,000	\$166,000
Total Cost				\$419,000



Northwest Territories Power Corporation
Business Case
Paulatuk New Living Accommodations

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.419M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.064%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$419	\$524	\$629	\$838
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$17	\$21	\$25	\$34
Return on Ratebase (\$000)	\$20	\$26	\$31	\$41
Sub-Total: Revenue Requirement Increase (\$000)	\$37	\$47	\$56	\$75
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$37	\$47	\$56	\$75
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.064%	0.080%	0.096%	0.128%



Northwest Territories Power Corporation
Business Case
Paulatuk New Living Accommodations

SUMMARY OF BUSINESS CASE RATIONALE

The current temporary staff accommodations in Paulatuk are not adequate. The hotel housing staff has limited space and is not always available in short notice situations. Also, the conditions at the hotel are deficient as rooms are shared frequently with unknown persons and food services are lacking.

NTPC has attempted to identify alternative lease or rental opportunities but has not been able to identify any. Therefore, to provide adequate temporary accommodations for staff, NTPC is proposing to acquire a two bedroom trailer and install it in Paulatuk. This will provide important safety and accommodation reliability benefits.

RECOMMENDATION

The Corporation recommends purchasing and installing a trailer at the Paulatuk plant as outlined in option 3. The total costs to complete the project are estimated to be \$0.419M.



Northwest Territories Power Corporation
Business Case
Paulatuk New Living Accommodations

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT / BACKGROUND

NTPC is proposing to undertake a project to install a new roof at the company's head office location in Hay River. The head office roof has been in service since the building was constructed in 1989. The roof is nearing the end of its serviceable life, and inspections of the structure have revealed deterioration of the waterproof membrane. The existing roof will be replaced with a new rolled roofing system, which will prevent water leaking into the building and potentially causing structural damage. If the roof is not addressed, the infiltration of water could cause structural damage to the interior of the building. In addition, health issues could potentially arise with the growth of mold.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option is not viable given the roof has reached the end of its useful life, and not replacing the structure will result in water leaks and pose health and safety risks to staff working at the location.

Option 2: Replace Roof at Corporate Head Office Estimated Costs: \$500,000

This option would entail the installation of a new roof at the Corporation's head office location in Hay River. This would involve the removal of the existing aggregate from the roof, and the installation of a new rolled asphalt roofing system.

The Corporation will realize the following benefits from the project:

1. **Water Leak Prevention:** The roof will be replaced thereby preventing water from leaking into the building and causing structural damage. Once a leak has occurred, the cost to correct the problem is expected to increase if interior structural damage results.
2. **Health and Safety:** The new roof will prevent the growth of mold that may occur if water seeps inside the building from a breach in the existing waterproof membrane. Mold growth would pose a series health and safety risk to the staff working in the corporate office and may render the building unusable until the remediation was complete.



Northwest Territories Power Corporation
Business Case
Head Office Roof Replacement

COST ESTIMATES

Table 1 – Budget Estimates

Construction

Description	2017/18
Payroll Regular	10,000
Payroll Overtime	2,500
Payroll Fringe Benefits	3,500
Superstructure	360,000
Contingency	48,000
Total	\$424,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$424,000	\$0	\$76,000	\$500,000
Total Project Cost				\$500,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 65 years at the recommended amortization rate. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.500M
- Amortization rate of 1.54%
- Return on Ratebase of 6.88%
- Allocation of costs to all zones.

Given the above assumptions, the average rate impact of the project for NTPC's customers is estimated at 0.04%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
Head Office Roof Replacement

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$500	\$625	\$750	\$1,000
Amortization Period (Approx. Years)	65	65	65	65
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$8	\$10	\$12	\$15
Return on Ratebase (\$000)	\$34	\$43	\$52	\$69
Sub-Total: Revenue Requirement Increase (\$000)	\$42	\$53	\$63	\$84
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$42	\$53	\$63	\$84
NTPC Total Revenue Requirement (\$000)	\$105,840	\$105,840	\$105,840	\$105,840
Average Percentage Rate Increase	0.04%	0.05%	0.06%	0.08%

SUMMARY OF BUSINESS CASE RATIONALE

NTPC is proposing to undertake a project to install a new roof at the company's head office location in Hay River. The roof is nearing the end of its useful life and needs to be replaced. The new roof will prevent water from leaking into the building and potentially causing structural damage. In addition, the project would prevent a potential health and safety risk that may arise if moisture seeped into the interior of the building causing extensive mold proliferation.

RECOMMENDATION

The Corporation recommends proceeding with the replacement of the roof at the corporate head office in Hay River as outlined in option 2. The total cost to complete the project is estimated to be \$0.500M.



Northwest Territories Power Corporation
Business Case
Head Office Roof Replacement

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

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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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Snare Rapids Excitation System Upgrade

NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to undertake a project to replace the current excitation system at the Snare Rapids plant. An excitation system is a key piece of equipment used to control the voltage of a power system and is used to provide stability to the system.

The current excitation system (GE Silco IV), which was installed in 1989, has passed its designed life expectancy and is experiencing various technical problems. NTPC has had two site visits by the manufacturer (GE) to attempt to resolve the problems but they were unsuccessful in resolving the issues.

In 2015, the Corporation hired an engineering consulting firm, Kestrel Power Engineering, to test the exciter. Based on the results of the testing and the age of the current system, Kestrel recommended its replacement to reduce the risk of unplanned outages. In addition, the operations team indicated that making repairs is becoming more difficult. Spare parts are limited due to the product's age. There is also a very limited pool of individuals with the expertise to service and maintain the current system.

Snare Rapids is the most important plant on the Snare Hydro system and needs to be continuously available for power generation and water control. All the plants on the Snare system operate effectively in sequence. Water from the Snare Rapids plant is used to run the other three plants. Snare Rapids is critical for the management of water on Snare Hydro system.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The option of doing nothing is not viable. The current excitation system is experiencing various technical problems. An engineering consulting firm has recommended that the current system be replaced to reduce the risk of unplanned outages at Snare Rapids and ensure the critically important Snare Rapids generation remains operational 24/7.

Option 2: Installation of new Exciter System

Estimated Costs: \$604,000

This project involves the replacement of the current excitation system at the Snare Rapids plant with a new excitation system. The benefits of this option are that it will improve the reliability of the Snare Rapids plant and the Snare Hydro system overall.

Installing a new excitation system will reduce the risk of outages at the Snare Rapids plant. Outside of its generation capacity, the Snare Rapids plant is critical to the management of water on the Snare Hydro system. Improving this plant's reliability effectively improves the reliability of the other plants on the Snare Hydro system as well.



Northwest Territories Power Corporation
Business Case
Snare Rapids Excitation System Upgrade

Table 1 – Budget Estimates

Project Design

Description	2016/17
Payroll Regular	28,000
Fringe Benefits	10,000
Consultants Lump Sum	11,000
Transportation	7,000
Meals	500
Contingency	17,000
Total Base Project Estimate	\$73,500

Project Construction

Description	2017/18
Payroll Regular	32,000
Payroll OT	3,000
Fringe Benefits	11,000
Consultants Lump Sum	11,000
Contractors Lump Sum	22,000
Transportation	6,000
Meals	4,000
Freight	2,000
Generator	230,000
Building	13,000
Contingency	100,000
Total Base Project Estimate	\$434,000

Project Cost Estimates

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2016/17	\$73,500	\$2,500	\$13,000	\$89,000
2017/18	\$434,000	\$2,500	\$78,500	\$515,000
Total				\$604,000



Northwest Territories Power Corporation
Business Case
Snare Rapids Excitation System Upgrade

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 60 years at the currently approved GRA amortization rates. The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.604M.
- Amortization rate of 1.67%.
- Return on Ratebase of 7.18%.
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.144%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$604	\$755	\$906	\$1,208
Amortization Period (Approx. Year)	60	60	60	60
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$10	\$13	\$15	\$20
Return on Ratebase (\$000)	\$43	\$54	\$65	\$87
Sub-Total: Revenue Requirement Increase (\$000)	\$53	\$67	\$80	\$107
Less: Estimated O&M Savings (\$000)	-	-	-	-
Total Revenue Requirement Impact (\$000)	\$53	\$67	\$80	\$107
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.144%	0.180%	0.216%	0.288%



Northwest Territories Power Corporation
Business Case
Snare Rapids Excitation System Upgrade

SUMMARY OF BUSINESS CASE RATIONALE

The current excitation system at the Snare Rapids plant has passed its designed life expectancy and is experiencing various technical problems. An excitation system is a key piece of equipment used to control the voltage of a power system and is used to provide stability to the system.

NTPC has had two site visits by the manufacturer (GE) to attempt to resolve the problems but they were unsuccessful. In 2015, the Corporation hired an engineering consulting firm to test the exciter. Based on the results of the testing and the age of the current system, the consultants recommended its replacement to reduce the risk of unplanned outages. The purchase and installation of a new excitation system can reduce the risk of unplanned outages at the Snare Rapids plant.

Snare Rapids is the most important plant on the Snare Hydro system, with the other hydro plants relying on water flow from Snare Rapids. Snare Rapids is critical for water management on the Snare Hydro system with water flow from the Rapids plant used to operate the other three plants. Improving this plant's reliability effectively improves the reliability of the other plants on the Snare system.

RECOMMENDATION

To ensure the reliability of the Snare Rapids plant, and the overall Snare Hydro system it is recommended the Corporation proceed with option 2. The total cost to complete the purchase and installation of a new excitation system for Snare Rapids is estimated at \$0.604M.



Northwest Territories Power Corporation
Business Case
Snare Rapids Excitation System Upgrade

Attachment A
Concordance Table Summarizing PUB Information Requirements and Business Case Information

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An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 3.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT

NTPC is proposing to undertake a project to replace the current distribution line to the Spillway 5B at Snare Rapids. The current line has been in service for nearly 60 years and is past its useful life. This project would involve installing approximately seven kilometers of new distribution line along with 30 new power poles.

BACKGROUND

A spillway is a structure used to provide the controlled release of flows from a dam or levee into a downstream area. Water does not normally flow over a spillway and it is typically used during flood periods. Spillways release floods so that the water does not overtop and damage or destroy a dam. Spillway 5B is used to control water for the entire Snare Hydro system.

Spillway 5B is located at the end of an arm (inlet) off the southern end of Big Spruce Reservoir. The spillway is a stop log controlled reinforced concrete structure comprising eight bays, two of which are equipped with electrical sill heaters. The stop logs are used to control the flow of water from the Snare River.

Stop logs are lifted by an electrically powered gantry crane with power supplied via the current distribution line from Snare Rapids. During the winter, the heaters on the equipped bay are used to prevent the logs from freezing so they can be moved as needed. Backup power is available via a gasoline powered generator. Most of the logs are removed and reinstalled during each year's normal operating cycle.

The placing and removal of stop logs requires the use of a crane and the crane requires power. In addition, winter operation requires a constant heat source to prevent the logs from freezing, necessitating a continuous reliable power source. The current distribution line to the spillway is past its useful life putting at risk the ability to place and remove stop logs at the spillway. This ability is a critical function and Dam Safety requirement. In order to ensure the spillway has a reliable power source, the current distribution line requires replacement with a new line.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option is not viable. The spillway requires a continuous reliable power source for the crane to move logs and for the heaters used to prevent the logs from freezing in the winter. The current distribution line to the spillway is nearly 60 years old and past its useful life, putting this capability at risk.

The stop logs at the spillway control the flow of water from the Snare River for the entire Snare Hydro system. The ability to place and remove stop logs is a critical function and Dam Safety requirement.



Option 2: Install new Distribution Line to Spillway 5B

Estimated Costs: \$1,229,000

This option would involve the installation of approximately 7 kilometers of new distribution line along with 30 new power poles to support the line. This new line would replace the current distribution line going from the Snare Rapids plant to the 5B Spillway.

The new line will provide Spillway 5B with a reliable power source for the crane used for the placement and removal of stop logs. It will also provide power for the heated bays during winter to prevent the stop logs from freezing. The benefits of ensuring the reliability of the spillway are as follows:

- Regulatory Compliance - The removal and placement of stop logs at the spillway is a requirement under Dam Safety Regulations
- Dam Reliability – Spillway 5B is a secondary structure responsible for controlling water flow and storage for the entire Snare Hydro system. If this structure is unable to regulate water levels, it would hinder the ability of NTPC to generate reliable power from the Snare Hydro System.
- Financial - If the ability to remove logs is hampered, dam failure could occur and the cost to repair the structure would be very high.
- Environmental – The spillway controls the release of water in flood situations. If the ability to remove logs is hampered, this risks significant amounts of water being released in an uncontrolled way with potentially significant negative environmental consequences.

COST ESTIMATE

Table 1 – Budget Estimates

DESIGN

Description	2017/18
Payroll Regular	\$26,000
Fringe Benefits	\$9,000
Contingency	\$10,000
Total	\$45,000



CONSTRUCTION

Description	2017/18	2018/19
Payroll Regular	-	159,000
Fringe Benefits	-	55,000
Transportation	-	222,000
Freight	30,000	-
Poles	120,000	-
Conductors	160,000	-
Contingency	93,000	131,000
Total	\$403,000	\$567,000

Project Estimated Costs

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$448,000	\$15,000	\$81,000	\$544,000
2018/19	\$567,000	\$16,000	\$102,000	\$685,000
Total Project Cost				\$1,229,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 47 years at the currently approved GRA amortization rates.

The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$1.229M.
- Amortization rate of 2.15%.
- Return on Ratebase of 7.18%.
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.308%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

**Table 2 – Sensitivity Analysis**

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$1,229	\$1,536	\$1,844	\$2,458
Amortization Period (Approx. Year)	47	47	47	47
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$26	\$33	\$40	\$53
Return on Ratebase (\$000)	\$88	\$110	\$132	\$176
Sub-Total: Revenue Requirement Increase (\$000)	\$115	\$143	\$172	\$229
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$115	\$143	\$172	\$229
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average % Rate Increase	0.308%	0.386%	0.463%	0.617%

SUMMARY OF BUSINESS CASE RATIONALE

The stop logs at Spillway 5B are used to control the flow of water from the Snare River for the entire Snare Hydro system. The ability to place and remove stop logs is a critical function and Dam Safety requirement.

The spillway requires a continuous reliable power source for the crane to move the stop logs and for the heaters used to prevent the logs from freezing in the winter. The current distribution line to the spillway is nearly 60 years old and past its useful life putting this ability at risk. Replacing the distribution line will improve dam reliability and mitigate potential environmental and financial risks that would arise if the stop log system was no longer functional.

RECOMMENDATION

To ensure Spillway 5B has a reliable power source and can continue its critical function to control water flow on the Snare Hydro system, NTPC recommends the installation of a new distribution line as outlined in option 2. The total costs to complete the project are estimated to be \$1.229M.



Attachment A

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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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Option section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Tulita Day Tank and Fuel System Upgrade

NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to upgrade the fuel day tank and fuel transfer system at the Tulita power plant. The Tulita power plant was constructed in 1995 with a total installed capacity of 1,100 kW. It has three diesel generators.

The plant has a 90,000L double-walled fuel storage tank that was built in 2006, and a single-walled rectangular oval day tank. The current single-walled day tank is no longer compliant with certain NTPC best practices, industry standards and current regulatory codes.

Also, the plant's diesel generators are not able to get sufficient fuel to operate effectively (fuel starvation). The cause of the fuel starvation is the fuel transfer system is not able to supply sufficient fuel to the engines. A number of factors are contributing to the lack of flow from the transfer system. These include:

- Fuel pumps – current pumps are near end of life and less effective at pumping fuel.
- Vent pipe – current vent pipe is too small.
- Fuel system design – day tank position reduces fuel pressure.

The Corporation monitors regulatory requirements and incorporates these requirements into the 5 year Capital Program. This program replaces/upgrades assets as required to ensure NTPC meets existing regulatory codes. In addition, the Capital Program is updated as regulatory changes occur, ensuring the Corporation continues to meet regulatory requirements.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

This is not a viable option. The current fuel day tank and fuel transfer system are no longer compliant with NTPC's internal best practices and industry standards (Canadian Standards Association, Underwriters Laboratories of Canada), as well as current regulatory codes.

Option 2: Upgrade Fuel Day Tank and Fuel Transfer System

Estimated Costs: \$570,000

This option would involve the reconfiguration of the current fuel transfer system and the installation of a new day fuel tank, fuel pumps, and various accessories. This project is part of a corporate initiative to upgrade the fuel tanks, piping, and related systems at diesel based plants. These upgrades will enhance plant safety, reliability and ensure compliance with current regulatory requirements. Consistent with this policy the proposed project consists of the following elements:

- Fuel transfer system redesign – New fuel system design increases fuel pressure on the system without the need to alter the height of the day tank
- New Day Tank - 250 gallon double-walled vertical cylindrical



Northwest Territories Power Corporation
Business Case
Tulita Day Tank and Fuel System Upgrade

- New Fuel Pumps - Two Franklin STP33 submersible turbine pumps installed (one serves as a backup)
- Vent Pipe - New larger vent pipe installed
- Various safety/emergency items such as pressure valves/switches/indicators, swing check valve (spills), emergency fill assembly

The benefits of completing the project are the safe transfer of fuel from the storage tank to the day tank. Sufficient fuel will be supplied to the diesel engines so they run more efficiently.

COST ESTIMATES

Table 1 – Budget Estimates

Description	2015/16	2017/18
Payroll Regular	27,000	89,000
Payroll Overtime	2,000	20,000
Payroll Fringe Benefits	7,000	31,000
Consultants Lump Sum	-	52,000
Contractors Lump Sum	-	84,000
Transportation	6,000	12,000
Accommodation	2,000	12,000
Meals	1,000	5,000
Freight	-	41,000
Fuel Storage - Tank Farm	-	12,000
Fuel Handling - Piping	-	5,000
Contingency	-	73,000
Total Base Project Estimate	\$45,000	\$436,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2015/16	\$45,000	\$0	\$10,000	\$55,000
2017/18	\$436,000	\$0	\$79,000	\$515,000
Total				\$570,000



Northwest Territories Power Corporation
Business Case
Tulita Day Tank and Fuel System Upgrade

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.570M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.087%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$570	\$713	\$855	\$1,140
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$23	\$29	\$35	\$46
Return on Ratebase (\$000)	\$28	\$35	\$42	\$56
Sub-Total: Revenue Requirement Increase (\$000)	\$51	\$63	\$76	\$102
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$51	\$63	\$76	\$102
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.087%	0.109%	0.130%	0.174%



Northwest Territories Power Corporation
Business Case
Tulita Day Tank and Fuel System Upgrade

SUMMARY OF BUSINESS CASE RATIONALE

The current fuel day tank and fuel transfer system at the Tulita plant are no longer compliant with certain NTPC internal best practices, industry standards and current regulatory codes. Also, the fuel transfer system at the plant provides insufficient fuel for the diesel engines to run effectively.

As part of an overall program at NTPC to upgrade the fuel tanks, piping, and related systems at diesel based plants, the Corporation proposes to address these concerns by upgrading the day tank and fuel transfer system. This will allow for the safe transfer of fuel from the storage tank to the day tank. In addition, the diesel engines will now receive sufficient supplies of fuel and run more efficiently.

RECOMMENDATION

The Corporation recommends proceeding with option 2, upgrading the day tank and fuel transfer system at the Tulita plant. The total costs to complete the project are estimated to be \$0.570M.



Northwest Territories Power Corporation
Business Case
Tulita Day Tank and Fuel System Upgrade

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page #3.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>

2018/19 Business Cases



NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to repaint Tank F at the Inuvik tank farm. Tank F was manufactured in 1976 and the current paint on the tank is the original. The tank has a capacity of nine million liters and is used to store production fuel for diesel generation in Inuvik, Fort McPherson and Tsiigehtchic. The paint on the tank is fading, and there are signs of pitting and rust on the tank.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

Tank F is now showing signs of pitting and rust. Leaving the tank in its current state could lead to tank failure. If the tank were to fail there could be a major diesel spill with significant environmental impacts and safety concerns for staff and the safety of the Inuvik tank farm facility.

Also, the tank would be unable to continue to store fuel. Tank F is now the only bulk fuel storage tank NTPC has in Inuvik and it is used to service the Inuvik plants (EMD & K-Plant), Fort McPherson and Tsiigehtchic. Therefore, keeping this tank in service is critical to the region's fuel supply and power plant operations.

Option 2: Paint Tank F Estimated Costs: \$584,000

This option would involve the washing and repainting of Tank F. The tank would be washed and then painted with a brush and roller. This method of painting is very labor intensive and requires extensive use of boom lifts as the tank is at a height of 50 feet. Local contractors would be used to complete the work.

The use of a brush and roller method to repaint the tank was selected for a number of environmental and safety reasons. Spraying the tank was not an option given the tanks close proximity to other buildings and the need to prevent the paint from impacting these structures. Also, the current paint on the tank is lead based and this restricts the techniques which can be used.

There will be two coats of paint applied. The first coat is a rust inhibitor and the second coat is a UV protection top coat to fully encapsulate the existing lead based paint. Labor rates in Inuvik are relatively high, due to the small, highly competitive labor market in the town. This has a significant impact on the cost of completing the project.

By repainting Tank F in the manner described, NTPC can complete the work in an environmentally responsible and safe way, and ensure the continued safety and reliability of the tank. The tank will be able to continue to store production fuel for use in Inuvik, Fort McPherson and Tsiigehtchic.



COST ESTIMATES

Table 1 – Budget Estimates

Description	2018/19
Payroll Regular	10,000
Payroll Overtime	4,000
Payroll Fringe Benefits	3,000
Contractors Lump Sum	317,000
Transportation	10,000
Accommodation	10,000
Meals	4,000
Equipment Rental	20,000
Freight	3,000
Contingency	114,000
Total Base Project Estimate	\$495,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2018/19	\$495,000	\$0	\$89,000	\$584,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.584M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.089%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.



Northwest Territories Power Corporation
Business Case
Inuvik Paint Tank F

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$584	\$730	\$876	\$1,168
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$24	\$29	\$35	\$47
Return on Ratebase (\$000)	\$28	\$36	\$43	\$57
Sub-Total: Revenue Requirement Increase (\$000)	\$52	\$65	\$78	\$104
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$52	\$65	\$78	\$104
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.089%	0.111%	0.134%	0.178%

SUMMARY OF BUSINESS CASE RATIONALE

Tank F was manufactured 40 years ago and the paint is showing signs of pitting and rust. The Corporation risks a structural failure if the tank is left in its current state, which would result in a major diesel spill and put the environment, staff and the entire Inuvik tank farm at risk. The tank would also be unable to continue to store fuel. It is critical that the tank remains in service given it supplies production fuel to Inuvik, Fort McPherson and Tsiigehtchic.

To maintain Tank F in good working order and ensure that it continues to operate in a safe and reliable way, it is essential that the tank is repainted. The Corporation has created a project plan to ensure the repainting can be completed in an environmentally safe way.

RECOMMENDATION

The Corporation recommends proceeding with the repainting of Tank F at the Inuvik tank farm as outlined in option 2. The total costs to complete the project are estimated to be \$0.584M.



Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

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A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Jackfish SCADA Host System Replacement

NEED FOR PROJECT

The Corporation is proposing to undertake a project to replace the Supervisory Control and Data Acquisition (SCADA) servers and host software system at the Jackfish power plant in Yellowknife. The equipment and software are over eight years old and are reaching the end of their useful life. The servers were installed in 2008 and are experiencing failures and rebooting issues.

The replacement of the hardware alone is not viable, as the present SCADA software version in use by NTPC is outdated. The software needs to be upgraded to allow NTPC to realize a whole host of operational improvements that will increase the Corporation's ability to carry out its strategic initiatives and deliver on its value proposition to its customers. This upgrade will allow NTPC to take advantage of advances in SCADA software that now supports enterprise scalability, open platforms for real time/historical data to present to WebPortal, customer load profiles, outage reporting and notifications, as well as financial and CMMS integration with SCADA.

BACKGROUND

NTPC undertook a large seven year program to upgrade communications and all supervisory field equipment. The equipment had been in service for 25-30 years and had reached the end of its serviceable life. All supervisory field equipment was replaced with the latest generation remote terminal units (RTUs), with expected life cycle of 25 years. These use current technology and standard protocols. An incremental step was carried out in 2008 to upgrade the SCADA host software to accept the newer generation RTUs.

The SCADA servers were installed in 2008 and are due to be replaced. The software is outdated and no longer supports the strategic initiatives of the Corporation. The current software does not support data integration with enterprise systems, which is now required to access real time and historical operational data for analysis for load forecasting, as well as water management and optimization of plants. The newer generation SCADA software supports operational training, improved alarm management, outage reporting and higher levels of ergonomics for operational displays, which the current legacy version does not support. The SCADA server software typically receives incremental upgrades every three to four years, with major upgrade every eight to ten years to keep up to changing requirements.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The reliability of the SCADA system cannot be assured without a phased in replacement of system hardware. The hardware is near end of life cycle and replacement parts are difficult to secure, which in turn negatively impacts the reliability of the SCADA system and reduces NTPC's operational ability to effectively deliver safe and reliable power generation and grid management. SCADA system reliability issues can result in the loss of revenues due to sustained power outage



Northwest Territories Power Corporation
Business Case
Jackfish SCADA Host System Replacement

durations lasting up to several hours without SCADA grid management. This risks damaging the Corporation's reputation as preferred power supplier in the Snare Zone.

Option 2: Replace SCADA Host System
Estimated Costs: \$1,906,000

This option entails replacing the SCADA servers and software system. The Corporation will evaluate the operational requirements such as energy management, generation automation, and data collection for optimizing grid management and to support renewables. A plan will be developed to upgrade the SCADA system based on these requirements. The new system will be implemented using the following phased in approach:

- 2017 – Scoping and defining operational requirements.
- 2018 – Planning, design and implementation of main SCADA system
- 2019 – Implementation of key features such as custom reporting, further data integration with office applications and operational training simulator.

The upgrade of the SCADA system will provide the following key benefits to the Corporation and its customers:

1. **Reliability:** Maintain reliability by ensuring SCADA system remains functional and online.
2. **Energy Management:** Improved energy management by utilizing improved current generation SCADA capabilities.
3. **Efficiency:** Provides automated data capture to better integrate and support business processes. This saves time, money and improves accuracy. Currently, operational staff manually enter data from SCADA displays into excel spreadsheets for daily reports. New generation SCADA software would support automated processes to transfer important operational information into office applications and corporate systems for data analysis. This aids in optimizing operations, load forecasting and water management, as well as allowing the Corporation to develop better tools for outage analysis and reports.
4. **Alignment of Production System (SCADA) with Corporate Systems:** Previously the SCADA hardware platform used high-end expensive business servers (Sun Servers) that required outside resources to provide system maintenance support. The SCADA upgrade addresses the key need to move towards modern, cost-effective x86 based hardware that is aligned with NTPC business system hardware, which allows a wider team of internal resources to support the hardware aspect of the production environment.
5. **Cost Savings:** Thousands of configured database points will be converted in a cost effective manner when upgrading to a newer version of the SCADA software.
6. **Alignment with Industry Standards and Best Practices:** The new system is aligned with regulator mandates and industry standards and best practices for industrial automation. It



Northwest Territories Power Corporation
Business Case
Jackfish SCADA Host System Replacement

provides advances in alarm management, electronic operator logbook, shift handover, lone/worker tracking, native web viewer and operator training simulator with Incident review. It also improves data management with excel integration and standard OPC connectivity to PI Historians or Corporate Web Servers. The new system provides compliance with standards in security and communication protocols, as well as improved operational displays for increased operator effectiveness. Lastly, it will provide enhanced operator training to improve job performance.

7. **Data Integration:** Enable historical and real time integration of data with office applications, web web servers, enterprise systems to report availability, production data, out of service, statistically information and grid management performance. Data Integration provides cost savings and a path to automate processes that were done manually by operational staff. In addition it helps to report on performance of equipment, service intervals, and to support strategic initiatives.

COST ESTIMATES

Table 1 – Budget Estimates

Planning

Description	2016/17	2017/18
Payroll Regular	67,000	25,000
Payroll O/T	7,000	-
Fringe Benefits	23,000	9,000
Consultants Lump Sum	60,000	20,000
Transportation	8,000	6,000
Accommodation	5,000	1,000
Meals	2,000	500
Contingency	20,000	7,000
Total	\$192,000	\$68,500



Northwest Territories Power Corporation
Business Case
Jackfish SCADA Host System Replacement

Design

Description	2017/18
Payroll Regular	33,000
Payroll O/T	4,000
Fringe Benefits	12,000
Consultants Lump Sum	360,000
Transportation	7,000
Accommodation	5,000
Meals	2,000
Contingency	50,000
Total	\$473,000

Construction

Description	2017/18
Payroll Regular	33,000
Payroll Regular O/T	3,000
Fringe Benefits	12,000
Contractors Lump Sum	400,000
Transportation	1,000
Accommodation	1,000
Meals	1,000
Contingency	51,000
Total	\$502,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2016/17	\$192,000	\$6,500	\$35,500	\$234,000
2017/18	\$1,043,500	\$43,000	\$193,500	\$1,280,000
2018/19	\$295,000	\$44,000	\$53,000	\$392,000
Total Project Cost				\$1,906,000



Northwest Territories Power Corporation
Business Case
Jackfish SCADA Host System Replacement

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 9 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$1.906M
- Amortization rate of 10.93%
- Return on Ratebase of 7.18%
- Allocation of costs to Snare Zone

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.93%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$1,906	\$2,383	\$2,859	\$3,812
Amortization Period (Approx. Years)	9	9	9	9
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$208	\$260	\$312	\$417
Return on Ratebase (\$000)	\$137	\$171	\$205	\$274
Sub-Total: Revenue Requirement Increase (\$000)	\$345	\$431	\$518	\$690
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$345	\$431	\$518	\$690
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average Percentage Rate Increase	0.93%	1.16%	1.39%	1.86%



Northwest Territories Power Corporation
Business Case
Jackfish SCADA Host System Replacement

SUMMARY OF BUSINESS CASE RATIONALE

The SCADA servers located in the Jackfish plant in Yellowknife have reached the end of their useful life and need to be replaced. The current equipment is over eight years old and are experiencing failures and rebooting issues, which impacts the reliability of the SCADA system. The importance of a reliable system cannot be overstated, as it reduces the risk of a sustained power outage from a system failure and helps maintain customer confidence in NTPC.

The host SCADA software system received an incremental update in 2008 and is now outdated and needs to be upgraded. The latest SCADA software will allow NTPC to realize numerous operational benefits including improved efficiency, energy and data management, along with annual cost savings. There will a better alignment of the production system with the corporate systems, and bring NTPC's system into alignment with industry standards and best practices.

RECOMMENDATION

The Corporation recommends proceeding with the replacement of the SCADA host system at its Jackfish power plant as outlined in option 2. The total costs to complete the project are estimated to be \$1.906M.



Northwest Territories Power Corporation
Business Case
Jackfish SCADA Host System Replacement

Attachment A

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Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 5.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Jackfish T5 Transformer Replacement

NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to undertake a project to replace the T5 transformer at the Jackfish power plant in Yellowknife. The T5 transformer was installed in 1958 and has reached the end of its useful life.

The transformer is connected to a reactor bank, which is an important component in the transmission network. The reactor is needed to lower the voltage at the end of the transmission line to allow the Jackfish transmission plant and Snare hydro line to synchronize hydro power generation when Snare generation comes on line. If the T5 transformer fails, NTPC will lose the support of the reactor, and without the reactor, it is not possible to connect the high voltage transmission line to the rest of the network at Jackfish when Snare hydro generation starts back up.

Transformers are long lead-time items requiring six to seven months to deliver once the asset has been purchased, with installation and commissioning requiring an additional month. Therefore, if the T5 transformer fails, plant operators will not be able to connect Snare hydro generation to the distribution system to supply Yellowknife with electricity. As a result, diesel generation will have to be used to supply Yellowknife with power until a new transformer is installed, which would cost the corporation millions of dollars in diesel fuel if it took several months to install a new transformer.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option is not viable given the current T5 transformer is obsolete and must be replaced. The decision to do nothing could potentially cost the Corporation millions of dollars if the transformer fails and it takes an extended period of time to replace the unit.

Option 2: Install New Transformer **Estimated Costs: \$789,000**

This option would consist of installing a new transformer at the Jackfish transmission plant in Yellowknife. The project would be implemented over a two year period as outlined below:

- 2018 - Test the transformer to ascertain its condition and salvage value. NTPC to complete high level design and write up specifications for the new transformer. Complete the tendering process and award the contract to the successful bidder.
- 2019 - Receive transformer and complete the installation and commissioning of the unit.



Northwest Territories Power Corporation
Business Case
Jackfish T5 Transformer Replacement

The installation of the new transformer would provide the Corporation with following key benefits:

- **Hydroelectric Power Reduces Generation Costs** – Replacing the transformer will allow NTPC to reliably deliver low cost hydro power to its customers and only use its diesel generation when hydro power generation is offline. This minimizes the use of diesel power generation, which is a much more costly form of power generation. Installing a new transformer avoids the situation of having an extended period of diesel power generation while the Corporation is awaiting delivery of a new transformer unit.
- **Environmental** – Continued access to hydro power reduces the environmental impact of power generation by reducing diesel generation thereby reducing hydrocarbon emissions from the burning of fossil fuel.

COST ESTIMATES

Table 1 – Budget Estimates

Planning

Description	2017/18
Consultants Lump Sum	9,000
Transportation	1,500
Meals	500
Contingency	3,000
Total	\$14,000

Design

Description	2017/18
Payroll Regular	16,000
Fringe Benefits	6,000
Contingency	7,000
Total	\$29,000



Northwest Territories Power Corporation
Business Case
Jackfish T5 Transformer Replacement

Construction

Description	2018/19
Payroll Regular	9,000
Payroll Regular O/T	3,000
Fringe Benefits	3,000
Contractors Lump Sum	35,000
Transportation	3,000
Accommodation	5,500
Meals	3,000
Freight	28,000
New Transformer	250,000
Oil Containment	140,000
Contingency	144,000
Total	\$623,500

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$43,000	\$1,400	\$7,700	\$52,100
2018/19	\$623,500	\$1,500	\$112,000	\$737,000
Total Project Cost				\$789,100

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 47 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$0.789M
- Amortization rate of 2.15%
- Return on Ratebase of 7.18%
- Allocation of costs to Snare Zone



Northwest Territories Power Corporation
Business Case
Jackfish T5 Transformer Replacement

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 0.20%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$789	\$986	\$1,184	\$1,578
Amortization Period (Approx. Years)	47	47	47	47
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$17	\$21	\$25	\$34
Return on Ratebase (\$000)	\$57	\$71	\$85	\$113
Sub-Total: Revenue Requirement Increase (\$000)	\$74	\$92	\$110	\$147
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$74	\$92	\$110	\$147
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average Percentage Rate Increase	0.20%	0.25%	0.30%	0.40%

SUMMARY OF BUSINESS CASE RATIONALE

The T5 transformer at the Jackfish power plant is over 50 years old and has reached the end of its useful life. It is essential the transformer be replaced to ensure the Corporation is able to continue to provide hydroelectric power to its customers in Yellowknife. Failure to replace the transformer may result in the unit failing, and require the Corporation to meet the power demands of the Snare Zone using costly diesel generation for an extended period, as there is typically a long lead time required to acquire and install a new transformer. It could cost the Corporation millions of dollars if the transformer fails and it takes an extended period of time to replace the unit. This would in turn impact customers, potentially leading to a significant increase in electricity rates. Therefore, it is critically important NTPC replace the T5 transformer with a new unit.

RECOMMENDATION

The Corporation recommends proceeding with the replacement of the T5 transformer at the Jackfish power plant in Yellowknife as outlined in option 2. This will allow NTPC to continue to provide reliable low cost hydroelectric power to the City of Yellowknife. The total costs to complete the project are estimated to be \$0.789M.



Northwest Territories Power Corporation
Business Case
Jackfish T5 Transformer Replacement

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
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Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



NEED FOR PROJECT / BACKGROUND

NTPC is proposing to undertake a project to replace a Detroit D4-71 G3 diesel generator at the Jean Marie River power plant. This G3 diesel unit's power output is not high enough to meet the power demand requirements of the community. The 70 kW capacity of the existing engine is 25 - 35% lower than the other generators in the Jean Marie plant, making the genset too small for this plant and compromising the overall plant reliability. The G1 and G2 gensets are generating over 95% of the plants power. Continued operation in this manner will shorten engine life and increase the frequency of minor and major overhauls thus increasing maintenance costs and reducing engine reliability.

In addition, this generator is an older unit that was manufactured in 1975 and its fuel efficiency is very poor averaging 2.5 kWh/L. As a result, the unit is only used when absolutely necessary to avoid power shortages during peak load periods, resulting in only 200 hours of use in 2015. The plant also has a G1 and G2 diesel generator with a power output of 106 kW and 90 kW, respectively. The G3's poor fuel efficiency has resulted in the majority of the power generation being produced by the G1 and G2 units. It is difficult to procure parts for the genset due to the age of the engine, and the unit produces high levels of exhaust emissions and noise levels are extreme at 110 dB (decibels).

Replacement of the G3 unit will allow the plant operator to better optimize the power generation. All three gensets will now be available as needed to generate power. This will allow the plant's power generation to be optimally shared among the gensets and prevent excessive engine wear.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option is not a viable option as it will not resolve any of the ongoing issues with the G3 diesel generator.

Option 2: Purchase and Install New Diesel Generator

Estimated Cost: \$625,000

This option requires the purchase and installation of new 106 kW air cooled Deutz generator to replace the existing Detroit D4-71 G3 generator. Various modifications will be required to the Programmable Logic Controller (PLC) to match the higher output of the new genset. The PLC unit determines the optimal engine mix based on load demand.



Northwest Territories Power Corporation
Business Case
G3 Engine Replacement Jean Marie River

The benefits of this option include:

- Higher power plant generation capacity that meets the community load requirements; which improves overall plant reliability, and prevents potential capacity shortfalls.
- Improved load sharing ability across all units at the plant, reducing potential future maintenance costs associated with relying primarily on two units to serve the majority of the generation requirements.
- Improved plant ventilation, reduced emissions and noise levels.

COST ESTIMATES

The estimated cost of the project is \$0.625M, with the table below showing the detailed budget breakdown for the combined 2018 to 2019 period.

Table 1 – Budget Estimates

Project Design

Description	2017/18
Payroll Regular	\$30,000
Payroll Fringe	\$10,500
Consultants Lump Sum	\$10,500
Transportation	\$1,500
Accommodation	\$1,000
Meals	\$500
Contingency	16,000
Total	70,000



Northwest Territories Power Corporation
Business Case
G3 Engine Replacement Jean Marie River

Project Construction

Description	2018/19
Payroll Regular	44,000
Payroll OT	21,000
Payroll Fringe	16,000
Contractors Lump Sum	98,000
Transportation	23,000
Accommodation	11,000
Meals	4,000
Equipment Rental	1,500
Diesel Engine	100,000
Freight	6,000
Power Cables	5,000
Control Cables	1,500
Piping	2,000
Duct Work	15,000
Contingency	108,000
Total	456,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$70,000	\$2,400	\$12,500	\$84,900
2018/19	\$456,000	\$2,500	\$81,600	\$540,100
Total Project Cost				\$625,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates.



Northwest Territories Power Corporation
Business Case
G3 Engine Replacement Jean Marie River

The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.625M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.10%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$625	\$781	\$938	\$1,250
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$25	\$32	\$38	\$51
Return on Ratebase (\$000)	\$30	\$38	\$46	\$61
Sub-Total: Revenue Requirement Increase (\$000)	\$56	\$70	\$84	\$111
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$56	\$70	\$84	\$111
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.10%	0.12%	0.14%	0.19%



Northwest Territories Power Corporation
Business Case
G3 Engine Replacement Jean Marie River

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation has identified the need to replace the G3 diesel generator at the Jean Marie River power plant. This generator is over 40 years old and no longer meets the requirement of NTPC.

The G3 unit's power output is significantly below that of the other generators in the plant and is too small given the power requirements of the Town of Jean Marie River. Installation of the new genset will result in increased power output and will be used on a regular basis. This will allow plant operators to optimize the generation mix and usage, as all three gensets will now be continuously available for power generation, allowing the power generation requirements to be spread more optimally among generating units. This will reduce excessive wear and tear on the other two gensets and result in improved engine reliability and efficiency. Furthermore, the generator produces high levels of exhaust emissions, and the age of the G3 unit makes it difficult to procure parts as the unit has become obsolete.

RECOMMENDATION

It is recommended that NTPC proceed with the replacement of the G3 generator as outlined in option 2. The total costs to complete the project are estimated to be \$0.625M.



Northwest Territories Power Corporation
Business Case
G3 Engine Replacement Jean Marie River

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
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A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Tangible benefits are described in the Analysis Of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis shown on page 4.</i>
A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Nahanni Butte Engine Replacement

NEED FOR PROJECT / BACKGROUND

The Corporation is proposing to undertake a project to replace the Detroit D4-71 diesel generator at the Nahanni Butte power plant. The Nahanni Butte power plant has three diesel generators. These include:

- G1 - CAT 3304 (80kW)
- G2 - Detroit D4-71 (75kW)
- G3 - Isuzu (90kW)

The Detroit D4-71 (G2) unit has 56,647 hours of use, and is nearly due for its second 30,000 hour major overhaul. This generator is an older unit that was manufactured in 1975. Exhaust emissions and noise (110 dB) on the unit are high. Parts availability is also difficult due to the units' age.

The G2 unit fuel efficiency is also quite poor averaging only 2.5kWh/L. The G2 unit is currently online much of the time and accumulated about 4,700 hours of running time in 2015.

With its 75 kW capacity, the G2 unit is also undersized to meet the community's needs. The required firm capacity (RFC) requirements as required by the PUB states that, if the largest engine was lost, the community peak would have to be met by 110% with the other two remaining engines.

At present to accommodate the current load in Nahanni Butte two generators have to be online at all times with peak load in the community recorded at 120kW. Given the RFC requirements of the PUB, the community will require a diesel generator with a 120 kW capacity.

In the event this new generator went down the other two existing units would be able to meet the 110% peak capacity requirement. Together they have 170 kW of capacity, which would exceed the 132 kW capacity requirement of the PUB (120 kW peak X 110% = 132 kW).

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The do nothing option is not a viable option. Based on the PUB's RFC requirements, the community requires a larger diesel generator with a minimum 120 kW capacity. Also, the current efficiency on the G2 unit is below the PUB's efficiency threshold.



Northwest Territories Power Corporation
Business Case
Nahanni Butte Engine Replacement

Option 2: Purchase and Install New Diesel Generator

Estimated Cost: \$632,000

This option requires the purchase and installation, of a new 120 kW generator (genset) to replace the existing G2 - Detroit D4-71 generator. Various modifications will be required to the programmable logic controller at the plant to match the higher output of the new genset. The existing skid mounted radiator and exhaust silencer will also be replaced.

The benefits of this option are summarized below:

- Significantly improved diesel engine efficiency resulting in reduced fuel use.
- Reduced exhaust emissions and noise levels benefitting the local environment.
- Greater plant capacity improving the reliability of the plant and compliance with the PUB's RFC requirements.

COST ESTIMATES

The estimated cost of the project is \$0.632M, with the table below showing the detailed budget breakdown for the combined 2018 to 2019 period.

Table 1 – Budget Estimates

Project Design

Description	2017/18
Payroll Regular	30,000
Payroll Fringe	10,000
Consultants Lump Sum	10,500
Transportation	3,000
Accommodation	1,000
Meals	500
Contingency	16,000
Total	\$71,000



Northwest Territories Power Corporation
Business Case
Nahanni Butte Engine Replacement

Project Construction

Description	2018/19
Payroll Regular	44,000
Payroll OT	21,000
Payroll Fringe	16,000
Contractors Lump Sum	98,000
Transportation	31,000
Accommodation	11,000
Meals	4,000
Equipment Rental	1,500
Diesel Engine	100,000
Freight	11,000
Power Cables	5,000
Control Cables	1,500
Piping	10,000
Contingency	106,000
Total	\$460,000

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$71,000	\$2,500	\$13,000	\$86,500
2018/19	\$460,000	\$2,500	\$83,000	\$545,500
Total Project Cost				\$632,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved GRA amortization rates.

The rate impacts were estimated based on the following assumptions:

- Net estimated capital cost of \$0.632M.
- Amortization rate of 4.04%.
- Return on Ratebase of 4.87%.
- Allocation costs to Thermal Zone only.



Northwest Territories Power Corporation
Business Case
Nahanni Butte Engine Replacement

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.096%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$632	\$790	\$948	\$1,264
Amortization Period (Approx. Year)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$26	\$32	\$38	\$51
Return on Ratebase (\$000)	\$31	\$38	\$46	\$62
Sub-Total: Revenue Requirement Increase (\$000)	\$56	\$70	\$84	\$113
Less: Estimated O&M Savings (\$000)	\$0	\$0	\$0	\$0
Total Revenue Requirement Impact (\$000)	\$56	\$70	\$84	\$113
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average % Rate Increase	0.096%	0.120%	0.145%	0.193%

SUMMARY OF BUSINESS CASE RATIONALE

In order to accommodate the current load requirement in Nahanni Butte, two of its three generators have to be online at all times. The peak load in the community currently is 120kW. Given the RFC requirements of the PUB, the community will require a diesel generator with a 120 kW capacity. The G2 genset is amongst the oldest generators at the plant, the least efficient, and smallest in terms of its capacity. It is also difficult to maintain given its age and parts availability, very noisy, and has significant exhaust emissions. Replacing the G2 unit with a new 120kW genset will provide benefits in fuel efficiency, reduced environmental harm, and increased plant capacity improving reliability of the plant.

RECOMMENDATION

It is recommended that NTPC proceed with the replacement of the G2 generator as outlined in option 2. The total costs to complete the project are estimated to be \$0.632M.



Northwest Territories Power Corporation
Business Case
Nahanni Butte Engine Replacement

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

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A discussion of all intangible benefits.	<i>All benefits are described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>



Northwest Territories Power Corporation
Business Case
Norman Wells Plant Replacement

NEED FOR PROJECT

The Corporation is proposing to undertake a project to replace the power plant in Norman Wells. The current plant requires extensive repairs due to the collapsing foundation. Steel culverts were originally incorporated into the design of the building's foundation to maintain the permafrost in the ground year round. However, the culverts have rusted and the building's floor has shifted causing cracks to form in the floor, and certain areas of the structure have sunk up to 30mm. The foundation has deteriorated to a point that repairing the structure will only provide a short term solution and the building will have to be replaced. An engineering consulting firm inspected the building in 2015 and concluded that their remediation recommendations would not completely fix the problem and would only defer the need to construct a new plant.

The issues with the building's foundation pose the following serious issues and risks:

- Safety - The foundation under the switchgear (feeder and generator breakers) is deficient and there is a risk of electrical faults that could result in unexpected electrical arc flash hazard, which places the staff at risk of serious personal injury or could potentially start a fire in the power plant.
- Reliability -The instability of the foundation poses a risk to the reliability of the plant. Collapse of the foundation around the gensets would render them inoperable or potentially result in significant damage to the units.
- Environmental Risks - The shifting floor could cause a major fuel or coolant leak in the plant causing significant environmental damage to the surrounding area.

BACKGROUND

The current NTPC power plant in Norman Wells was first commissioned in 1961 to supply power to the town. Imperial Oil built a new power plant in the late 1990s and began to supply the power to NTPC's standby plant. This power is in turn distributed by NTPC from the standby plant to the Town of Norman Wells. Whenever the Esso plant is shut down for routine maintenance or unforced outages, NTPC's standby plant operates its generators and supplies emergency power to the town.

The plant was designed to not disturb the permafrost under the power plant foundation. Culverts were placed on top of the permafrost ground and then a gravel pad was constructed over top of the culverts. The plant's concrete slab foundation was then placed on top of the gravel pad. The design of the foundation would allow the permafrost to remain in the ground by leaving the ends of the culverts open during the winter and closing them in the summer. Over time, the culverts have severely rusted causing the floor of the plant to settle and completely collapse in certain areas. As a result of the rusting, sink holes were discovered under the concrete floor.

The Corporation places the diesel generators on genset pads, which are in turn placed on steel piles that provide firm support to the units. However, the floor around the pads is severely cracked



Northwest Territories Power Corporation
Business Case
Norman Wells Plant Replacement

and the floor sounds very hollow under foot traffic. The floor in the switchgear room has sunk by 30 mm, and the concrete floor below the wall that divides the genset bay and the switchgear bay has sunk to the degree that the wall no longer rests on the concrete floor.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The current plant in Norman Wells has serious problems with its foundation and is in need of extensive repairs. The do nothing option is not viable as it would result in the continued deterioration of the building's foundation, possibly resulting in an extended loss of power generation and exposing the Corporation and the staff to unnecessary risk. Collapse of the foundation could potentially take the current plant offline permanently and require the Corporation to ship rental units to Norman wells as a temporary measure until a new plant is put in place.

Option 2: Repair the Power Plant Foundation

Estimated Costs: \$470,000 to \$720,000

This option would consist of repairing the plant foundation as recommended by an external engineering consultant. The consultant inspected the building in September of 2015 and issued the following recommendations:

- Implement mudjacking and/or void grouting technique to lift and level the foundation.
- Add micropiles or deep piles to provide local support to the equipment.

However, none of the above remediation methods will address all problem areas. Slab removal and replacement or sub excavation and insertion of needle beams were not deemed practical due to the significant impact on plant operation or restricted access.

The consultant identified two potential concepts that could provide interim solutions for the existing plant. Concept one had an estimated cost of \$720k, while concept two was less costly with an estimated cost of \$470k.

This option is not optimal, as the ground is expected to continue to settle and any remediation undertaken will only defer the need for a new plant.

Option 3: New Modular Power Plant

Estimated Costs: \$4.6M

This option entails the purchase of a new modular diesel generator and building. The new diesel generator is rated for 2 MW (4.16 kV) and has enough generation capacity to meet the needs of Norman Wells. The modular building is essentially a 40 foot shipping container with special enclosures designed and fabricated by the genset supplier. This type of building is significantly less expensive than a custom building that meets NTPC's specifications.



Northwest Territories Power Corporation
Business Case
Norman Wells Plant Replacement

The project includes the installation of a new 4.16 kV switchgear, which will include two breakers for the diesel units and one for the Imperial Oil power generation infeed. The project will also require the installation of two feeder breakers and a station service breaker. The total project cost includes the mechanical and electrical installation and commissioning. The existing distribution system will be reused along with the existing 90,000L storage tank and the EM5 genset. The current plant site will be used to allow connection to the existing distribution line electrical connections and reuse of the existing distribution transformers and infrastructure.

The purchase and installation of the new power plant will provide the following key benefits to the Corporation and its customers:

- **Reliability** – A new plant will provide a stable operating environment and remove the risk of an unexpected shift in the foundation resulting in damage to the plant and its operating assets. The overall plant reliability will be improved with the addition of a new genset and the retaining of the current EM5 genset for backup power generation, which can also be used during peak load demand if required. This will ensure that the plant is able to meet customer power demand as required.
- **Environmental** – The new plant will have a stable foundation that will minimize the risk of an oil or coolant leak and the resulting environmental damage and cleanup costs.
- **Safety** – The project will reduce the risk of electrical faults and potential arc flashes that could start a fire in the plant or injure staff.

COST ESTIMATES

Table 1 – Budget Estimates

Design

Description	2017/18
Payroll Regular	40,000
Payroll Overtime	3,000
Payroll Fringe Benefits	14,000
Consultants Lump Sum	17,000
Transportation	6,500
Accommodation	1,500
Meals	500
Contingency	25,000
Total	\$107,500



Northwest Territories Power Corporation
Business Case
Norman Wells Plant Replacement

Construction

Description	2017/18	2018/19
Payroll Regular		33,000
Payroll Overtime		26,000
Payroll Fringe Benefits		12,000
Contractors Lump Sum	526,000	-
Transportation	-	15,000
Accommodation	-	8,000
Meals	-	9,500
Freight	25,000	-
New 2MW Genset	-	1,300,000
New Switchgear	-	750,000
Temporary Site Protection	-	125,000
Gravel Foundation	-	50,000
Contingency	165,000	699,000
Total	\$716,000	\$3,027,500

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$823,500	\$27,600	\$148,000	\$999,100
2018/19	\$3,027,500	\$28,400	\$545,000	\$3,600,900
Total Project Cost				\$4,600,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$4.6M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone



Northwest Territories Power Corporation
Business Case
Norman Wells Plant Replacement

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.70%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$4,600	\$5,750	\$6,900	\$9,200
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$186	\$232	\$279	\$372
Return on Ratebase (\$000)	\$224	\$280	\$336	\$448
Sub-Total: Revenue Requirement Increase (\$000)	\$410	\$512	\$615	\$820
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$410	\$512	\$615	\$820
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.70%	0.88%	1.05%	1.40%

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation's power plant in Norman Wells has major structural problems and needs to be replaced. The building foundation is collapsing and poses dangerous safety and environmental risks, which has the potential to negatively impact the plant's reliability and ability to generate power. It is imperative NTPC replace the plant to ensure the town has access to reliable power generation and ensure the safety of the Corporation's employees. The purchase of a new 2 MW genset will add additional generation capacity to the plant and the existing EM5 genset will be retained for backup generation thereby improving the plants ability to meet the future power demands of the community.

RECOMMENDATION

The Corporation recommends proceeding with procurement, construction and commissioning of a new power plant as outlined in option 3. This will allow NTPC to meet its obligation to provide safe, reliable power to the Town of Norman Wells in an environmentally responsible manner. The total costs to complete the project are estimated to be \$4.6M.



Northwest Territories Power Corporation
Business Case
Norman Wells Plant Replacement

Attachment A

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A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>

Appendix C

Reliability and Quality of Service



System Reliability Report

Fiscal Year 2015-16

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Executive Summary

Outage reporting practices at NTPC have been evolving over the past five years. The Corporation joined the Canadian Electricity Association (CEA) Service Continuity Committee in 2011, and participated in the CEA's annual data collection for the first time in that year. This reporting required adjustments to outage categorization and calculation methodologies to better align with the CEA program requirements. Outage events which occurred prior to July 2011 were not originally recorded according to the CEA guidelines. These events have been calculated and assigned to CEA categories based on their original classification in order to provide a full five years of history for trend analysis. However, these events were not reviewed on an individual basis for compliance with current reporting methodologies.

Under CEA reporting guidelines, other utilities are not included in customer counts. NTPC reliability results presented in the first section of this report follow this practice. The Public Utilities Board (PUB) has also directed NTPC to submit data on the reliability of its bulk supply to Northland Utilities on the Taltson and Snare systems. These results are provided in the second section of this document, as "NUL Supply Point Availability".

Most Prominent Events (MPEs) have been identified using guidelines developed by the Institute of Electrical and Electronics Engineers (IEEE). This methodology is known as the IEEE 2.5 Beta method. The IEEE 2.5 Beta Method recommends using five years of historic data to establish a baseline for identifying MPEs. Three years of historic data is considered the minimum acceptable for this methodology.

NTPC baselines for MPE identification were calculated in 2012 using three years of available historic data. This smaller data set resulted in artificially low baselines for several communities, and tended to over-identify MPEs. Additional restrictions were applied to MPEs identified by this initial application of the IEEE 2.5 Beta methodology to prevent outages caused by events within the control of the utility from being classified as MPEs. Examples of outage causes identified as "ineligible" for MPE classification include: Human Element; Planned; and Loss of Supply outages caused by equipment failures within generating stations.

NTPC has currently established an upper threshold of a System Average Interruption Frequency (SAIFI) of 10 for each isolated system in its service area. 3-year or longer trends of increasing outage frequency are also identified for action when they occur.

Definitions

SAIDI

System Average Interruption Duration Indicator: Total duration of all interruptions for an average customer during the reporting period.

$$\frac{\sum [OutageTime(h) * Total\#of\ Customers\ Interrupted]}{Total\#of\ Customers\ Served}$$

SAIFI

System Average Interruption Frequency Indicator: Average number of times that a system customer experiences an outage during the reporting period.

$$\frac{\sum [Total\#of\ Customers\ Interrupted]}{[Total\#of\ Customers\ Served]}$$

NTPC Reliability

Snare Hydro System

- Behchoko
- Con & Giant Mines
- Dettah

Taltson Hydro System

- Fort Smith
- Fort Resolution

Diesel / Gas Systems

- Aklavik
- Colville Lake
- Deline
- Fort Good Hope
- Fort Liard
- Fort McPherson
- Fort Simpson
- Gameti
- Inuvik
- Jean Marie River
- Lutsel K'e
- Nahanni Butte
- Norman Wells
- Paulatuk
- Sachs Harbour
- Tsiigehtchic
- Tuktoyaktuk
- Tulita
- Ulukhaktok
- Wha Ti
- Wrigley

NTPC Customer Summaries

Summarized system reliability for all locations where NTPC supplies electricity directly to customers.

RESULTS

Figure 1: Service Continuity Results by Fiscal Year (Including Most Prominent Events)

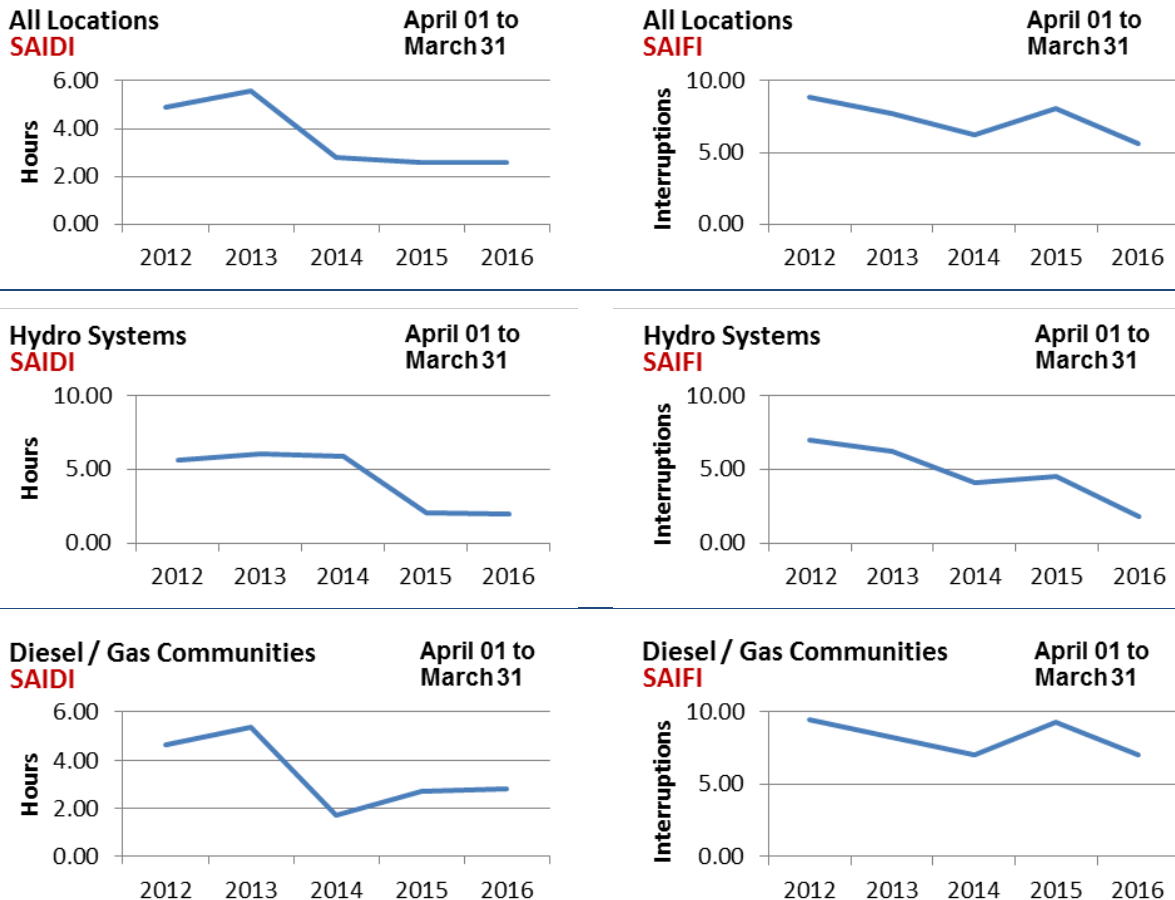
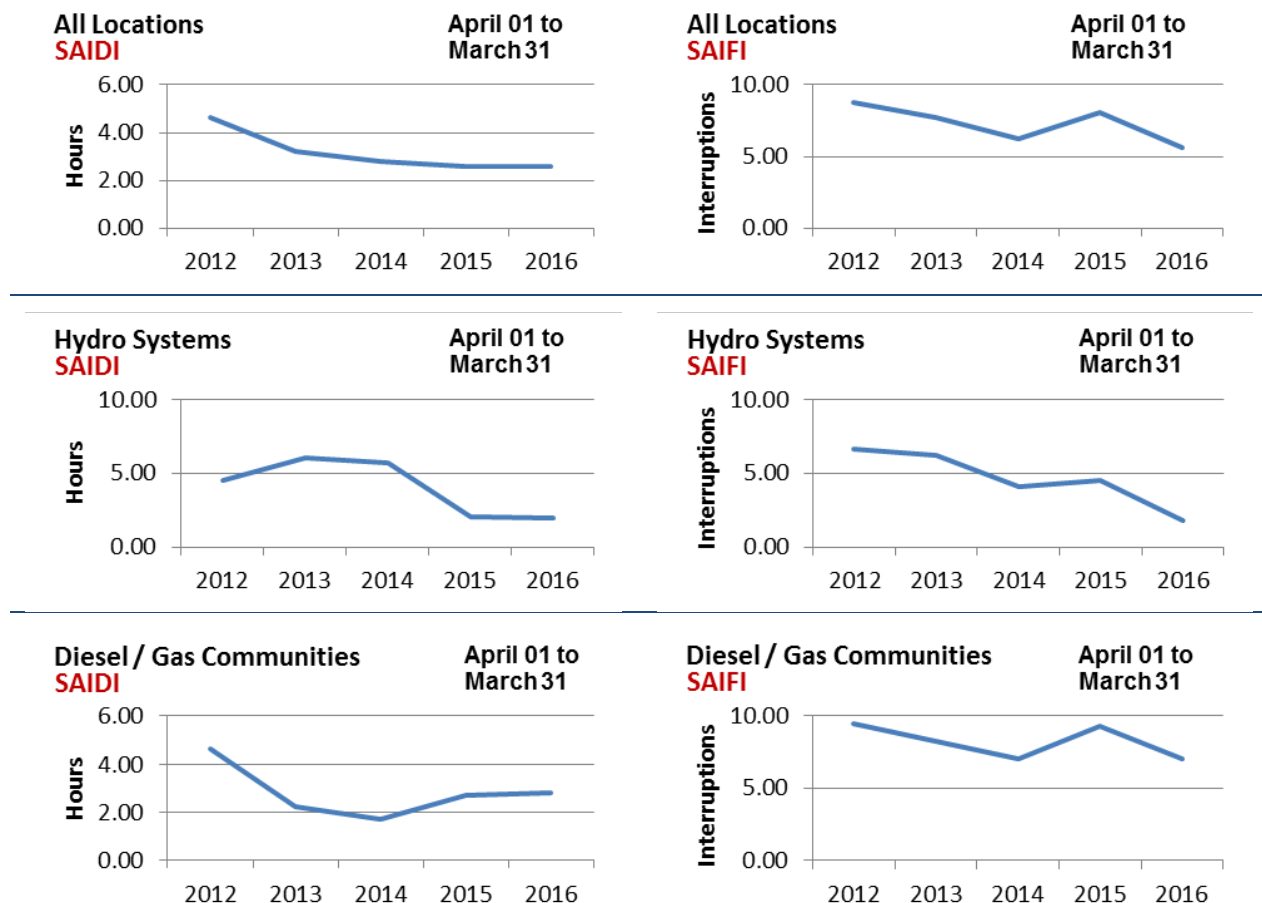


Figure 2: Service Continuity Results by Fiscal Year (Excluding Most Prominent Events)

INTERPRETATION

NTPC has two identified Most Prominent Events (MPE) in the past five years. A 10-day shutdown of the Nahanni Butte generating plant and distribution system in June 2012 due to flooding and evacuation of the community had a significant impact on both the corporate-level and Diesel / Gas Communities SAIDI results in the 2013 fiscal year, but does not affect the SAIDI results for Hydro Systems, or SAIFI for any of the measured groups.

In the 2011-12 fiscal year, customer interruptions resulting from the collision of a military helicopter with the Snare transmission line in February 2012 are also identified as an MPE. This event had a measurable impact on the SAIDI results for the Snare System and Hydro Systems aggregate in 2012. However, the impact on NTPC corporate results is less significant due to the relatively small number of NTPC serviced customers on the Snare System.

Interruption frequency in the Hydro zones dropped substantially in the 2015 and 2016 fiscal years. This reduction is partly due to the stabilizing effect of diesel operation in Yellowknife, required by low water conditions on the Snare and Bluefish hydro systems between July, 2014 and April, 2016.

Table 1: 2015-16 Service Continuity Results**All Locations****April 01, 2015 to March 31, 2016 8616 Total Customers****Sustained Interruptions (>= 1 Minute Duration)**

	Unknown /Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
Customer-Hours	234.09	2148.24	15921.72	158.31	1020.00	2344.91	27.00	73.87	11.17	127.02	22066
Customer-Interruptions	1411	1667	41250	228	255	1886	162	554	1042	217	48672
Interruption Events	19	10	169	4	1	7	1	1	4	7	223
SAIDI	0.03	0.25	1.85	0.02	0.12	0.27	0.00	0.01	0.00	0.01	2.56
SAIFI	0.16	0.19	4.79	0.03	0.03	0.22	0.02	0.06	0.12	0.03	5.65

Table 2: 2015-16 Service Continuity Results for Snare & Taltson Systems**Hydro Systems****Including Most Prominent Events****April 01, 2015 to March 31, 2016 1564 Total Customers****Sustained Interruptions (>= 1 Minute Duration)**

	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
Customer-Hours	26.83	72.91	2229.65	23.31	1020.00	3.21	0.00	0.00	0.47	2.39	3379
Customer-interruptions	31	60	1119	3	255	1	0	0	1	2	1472
Interruption Events	2	5	5	3	1	1	0	0	1	2	20
SAIDI	0.02	0.05	1.43	0.01	0.65	0.00	0.00	0.00	0.00	0.00	2.16
SAIFI	0.02	0.04	0.72	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.94

Table 3: 2015-16 Service Continuity Results for Diesel / Gas Systems**Diesel / Gas Systems****Including Most Prominent Events****April 01, 2015 to March 31, 2016****6316 Total Customers****Sustained Interruptions (>= 1 Minute Duration)**

	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
Customer-Hours	126.03	2075.33	13515.07	135.00	0.00	1562.70	27.00	73.87	10.70	0.00	17526
Customer-interruptions	955	1607	38505	225	0	1479	162	554	1041	0	44528
Interruption Events	12	5	151	1	0	5	1	1	3	0	179
SAIDI	0.02	0.33	2.14	0.02	0.00	0.25	0.00	0.01	0.00	0.00	2.77
SAIFI	0.15	0.25	6.10	0.04	0.00	0.23	0.03	0.09	0.16	0.00	7.05

Snare System

NTPC customers on the Snare System include Behchoko, Dettah, and industrial (mine) sites within the city of Yellowknife.

RESULTS

Figure 3: Service Continuity Results by Fiscal Year for NTPC Snare System Customers (Including Most Prominent Events)

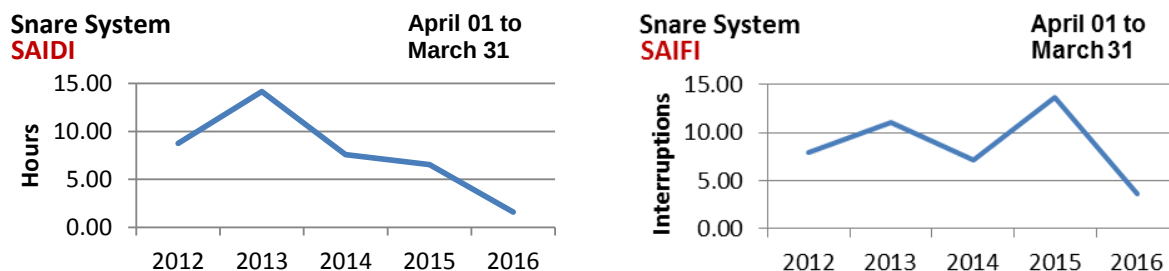
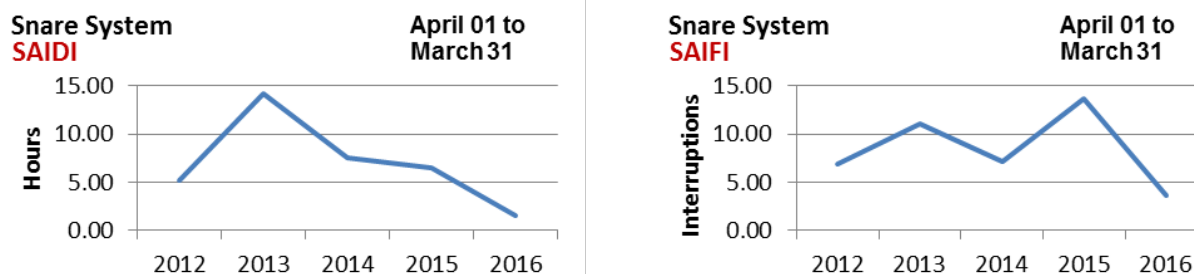


Figure 4: Service Continuity Results by Fiscal Year for NTPC Snare System Customers (Excluding Most Prominent Events)



INTERPRETATION

In the 2011-12 fiscal year, customer interruptions resulting from the collision of a military helicopter with the Snare transmission line in February 2012 are identified as an MPE. This event had a measurable impact on the SAIDI results for the Snare System and Hydro Systems aggregate in 2012.

NTPC initiated a reliability improvement program in the 2013 fiscal year with an objective to reduce the frequency of interruptions on this system to an annual SAIFI of 6 or less by 2015. Forest fire activity in the summer of 2014 caused multiple interruptions on the Snare System transmission lines, resulting in a high SAIFI for the 2015 fiscal year. However, many of these interruptions were relatively short in duration, allowing for continued improvement in SAIDI compared to previous years.

Low water conditions at the Snare and Bluefish hydro generating stations required operation of diesel generation at NTPC's Jackfish power plants between July 2014 and April 2016. Diesel operation mitigated the impact of transmission line interruptions on the Snare System during this period, and improved overall system stability, producing SAIFI and SAIDI results that were significantly better than the targets.

Table 4: Service Continuity Results for NTPC Customers on the Snare System (Including Most Prominent Events)

April 01, 2015 to March 31, 2016 736 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.11	0.00	0.24	0.00	0.00	1.06	0.00	0.00	0.00	0.17	1.58
SAIFI	0.58	0.00	2.21	0.00	0.00	0.55	0.00	0.00	0.00	0.29	3.63
April 01, 2014 to March 31, 2015 724 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.03	0.00	6.10	0.00	0.00	0.02	0.00	0.00	0.00	0.38	6.53
SAIFI	0.16	0.00	13.23	0.00	0.00	0.01	0.00	0.00	0.00	0.45	13.84
April 01, 2013 to March 31, 2014 731 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	2.55	0.00	4.25	0.00	0.05	0.73	0.00	0.00	0.00	0.09	7.66
SAIFI	1.02	0.00	5.21	0.00	0.01	1.01	0.00	0.00	0.00	0.04	7.30
April 01, 2012 to March 31, 2013 706 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.01	0.03	10.56	0.01	0.00	1.21	0.00	0.00	0.00	2.49	14.32
SAIFI	0.56	0.16	8.73	0.00	0.00	0.29	0.00	0.00	0.00	1.55	11.29
April 01, 2011 to March 31, 2012 718 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.04	0.00	8.30	0.00	0.00	0.00	0.00	0.00	0.10	0.31	8.75
SAIFI	0.16	0.00	6.71	0.00	0.00	0.00	0.00	0.00	0.84	0.31	8.03

Table 5: Service Continuity Results for NTPC Serviced Customers on the Snare System (Excluding Most Prominent Events)

April 01, 2015 to March 31, 2016			736 Customers							
Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
0.11	0.00	0.24	0.00	0.00	1.06	0.00	0.00	0.00	0.17	1.58
0.58	0.00	2.21	0.00	0.00	0.55	0.00	0.00	0.00	0.29	3.63
April 01, 2014 to March 31, 2015			724 Customers							
Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
0.03	0.00	6.10	0.00	0.00	0.02	0.00	0.00	0.00	0.38	6.53
0.16	0.00	13.23	0.00	0.00	0.01	0.00	0.00	0.00	0.45	13.84
April 01, 2013 to March 31, 2014			731 Customers							
Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
2.55	0.00	4.25	0.00	0.05	0.73	0.00	0.00	0.00	0.09	7.66
1.02	0.00	5.21	0.00	0.01	1.01	0.00	0.00	0.00	0.04	7.30
April 01, 2012 to March 31, 2013			732 Customers							
Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
0.01	0.03	10.56	0.01	0.00	1.21	0.00	0.00	0.00	2.49	14.32
0.56	0.16	8.73	0.00	0.00	0.29	0.00	0.00	0.00	1.55	11.29
April 01, 2011 to March 31, 2012			718 Customers							
Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
0.04	0.00	4.79	0.00	0.00	0.00	0.00	0.00	0.10	0.31	5.24
0.16	0.00	5.72	0.00	0.00	0.00	0.00	0.00	0.84	0.31	7.04

Table 6: Generation Cause Contributions to Loss of Supply Interruptions for NTPC Customers on the Snare System

April 01, 2015 to March 31, 2016 736 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2014 to March 31, 2015 724 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00	0.00	0.23
SAIFI	0.00	0.00	0.00	0.00	1.01	0.00	0.00	0.00	0.00	1.01
April 01, 2013 to March 31, 2014 731 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2012 to March 31, 2013 732 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.21	0.00	0.27
SAIFI	0.00	0.00	0.00	0.15	0.00	0.00	0.31	1.68	0.00	2.14
April 01, 2011 to March 31, 2012 718 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

**Table 7: Transmission Cause Contributions to Loss of Supply Interruptions for NTPC Customers on the Snare System
(Including Most Prominent events)**

April 01, 2015 to March 31, 2016 736 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	2.02	0.91	7.25	0.00	0.00	0.00	0.00	10.18
SAIFI	1.57	0.98	3.94	0.00	0.00	0.00	0.00	6.49
April 01, 2014 to March 31, 2015 724 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.08	2.29	2.39	0.00	0.00	0.00	3.53	8.30
SAIFI	1.08	1.85	2.69	0.00	0.00	0.00	1.15	6.77
April 01, 2013 to March 31, 2014 731 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	4.95	0.00	0.00	0.00	0.00	0.00	0.74	5.69
SAIFI	7.38	0.00	0.00	0.00	0.00	0.00	1.00	8.38
April 01, 2012 to March 31, 2013 732 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.40	2.57	1.22	0.00	0.00	0.00	0.00	4.19
SAIFI	1.29	0.99	1.97	0.00	0.00	0.00	0.00	4.25
April 01, 2011 to March 31, 2012 618 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.08	2.29	2.39	0.00	0.00	0.00	3.53	8.30
SAIFI	1.08	1.85	2.69	0.00	0.00	0.00	1.15	6.77

**Table 8: Transmission Cause Contributions to Loss of Supply Interruptions for NTPC Customers on the Snare System
(Excluding Most Prominent events)**

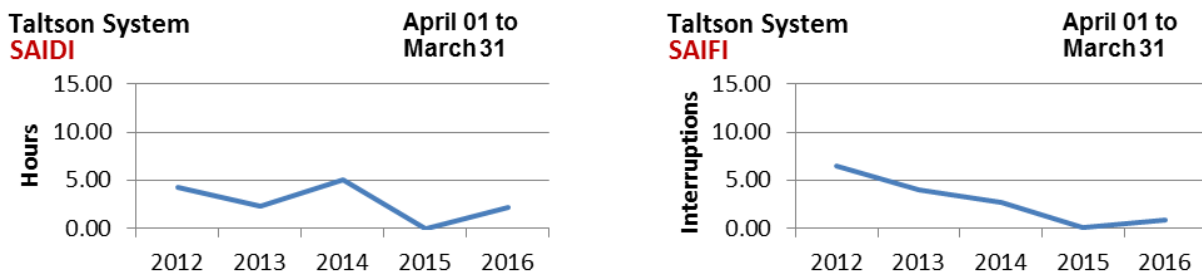
April 01, 2015 to March 31, 2016		736	Customers					
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	2.02	0.91	7.25	0.00	0.00	0.00	0.00	10.18
SAIFI	1.57	0.98	3.94	0.00	0.00	0.00	0.00	6.49
April 01, 2014 to March 31, 2015		724	Customers					
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.08	2.29	2.39	0.00	0.00	0.00	0.03	4.79
SAIFI	1.08	1.85	2.69	0.00	0.00	0.00	0.15	5.77
April 01, 2013 to March 31, 2014		731	Customers					
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	4.95	0.00	0.00	0.00	0.00	0.00	0.74	5.69
SAIFI	7.38	0.00	0.00	0.00	0.00	0.00	1.00	8.38
April 01, 2012 to March 31, 2013		732	Customers					
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.40	2.57	1.22	0.00	0.00	0.00	0.00	4.19
SAIFI	1.29	0.99	1.97	0.00	0.00	0.00	0.00	4.25
April 01, 2011 to March 31, 2012		618	Customers					
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.08	2.29	2.39	0.00	0.00	0.00	3.53	8.30
SAIFI	1.08	1.85	2.69	0.00	0.00	0.00	1.15	6.77

Taltson System

NTPC customers on the Taltson System include Fort Smith and Fort Resolution.

RESULTS

Figure 5: Service Continuity Results by Fiscal Year for NTPC Taltson System Customers¹



¹ The Taltson system has not experienced any interruptions identified as Most Prominent Events between April 1, 2012 and March 31, 2016. As a result, data including and excluding Most Prominent Events will not be presented separately for this system.

INTERPRETATION

Interruption rates and durations on the Taltson system are among the lowest in NTPC's operating area.

Table 9: Service Continuity Results for NTPC Customers on the Taltson System

April 01, 2015 to March 31, 2016 1564 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.02	0.05	1.43	0.01	0.65	0.00	0.00	0.00	0.00	0.00	2.16
SAIFI	0.02	0.04	0.72	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.94
April 01, 2014 to March 31, 2015 1562 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
SAIFI	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19
April 01, 2013 to March 31, 2014 1559 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.65	1.12	0.44	1.13	0.13	0.78	0.00	0.00	0.00	0.80	5.06
SAIFI	0.36	0.95	0.77	0.35	0.00	0.19	0.00	0.00	0.00	0.06	2.67
April 01, 2012 to March 31, 2013 1600 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.05	0.11	1.29	0.04	0.00	0.01	0.95	0.00	0.00	0.00	2.46
SAIFI	0.11	0.09	2.80	0.01	0.00	0.00	1.01	0.00	0.00	0.00	4.03
April 01, 2011 to March 31, 2012 1579 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.31	0.00	1.94	1.82	0.00	0.11	0.00	0.00	0.00	0.06	4.24
SAIFI	0.54	0.00	4.90	0.97	0.00	0.11	0.00	0.00	0.01	0.00	6.54

Table 10: Generation Cause Contributions to Loss of Supply Interruptions for NTPC Customers on the Taltson System

April 01, 2015 to March 31, 2016 1564 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.39	0.00	0.04	0.00	0.00	0.00	0.00	0.43
SAIFI	0.00	0.00	0.18	0.00	0.16	0.00	0.00	0.00	0.00	0.35
April 01, 2014 to March 31, 2015 1562 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2013 to March 31, 2014 1559 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2012 to March 31, 2013 1600 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.51	0.87
SAIFI	0.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	1.36
April 01, 2011 to March 31, 2012 1579 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.77
SAIFI	0.00	0.00	0.82	0.00	0.00	0.00	0.00	0.00	0.00	0.82

Diesel / Gas Systems

Diesel / gas communities include all communities not connected to a hydro transmission grid.

RESULTS

Figure 6: Service Continuity Results by Fiscal Year for NTPC Diesel / Gas System Customers (Including Most Prominent Events)

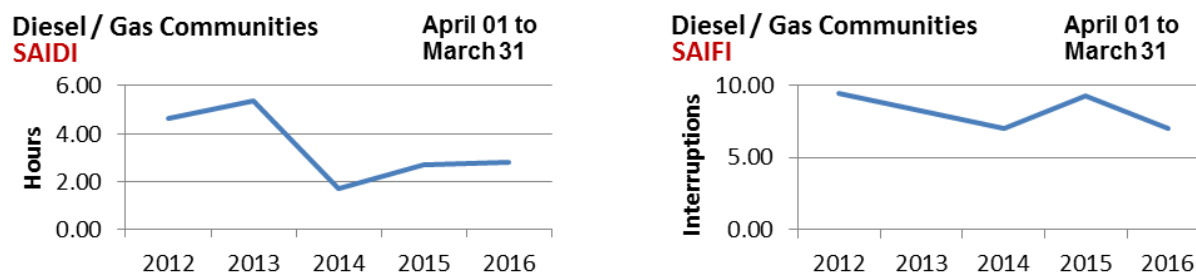
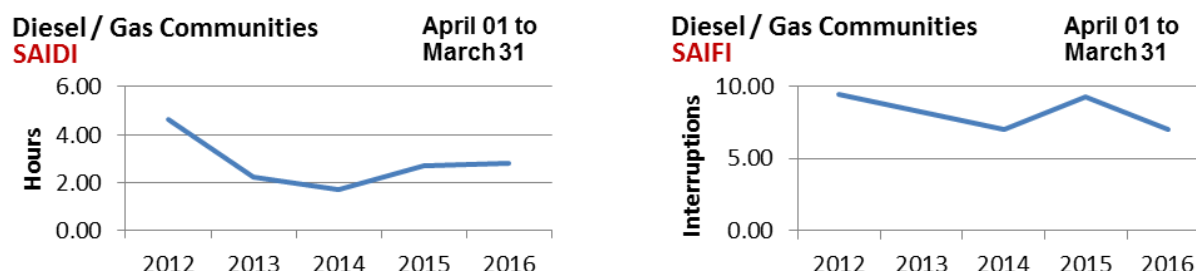


Figure 7: Service Continuity Results by Fiscal Year for NTPC Diesel / Gas System Customers (Excluding Most Prominent Events)



INTERPRETATION

One MPE has been identified for the diesel/gas communities group during the last five years. This is the flooding, evacuation, and 10-day shut-down of electrical generation and supply in the community of Nahanni Butte during the summer of 2012. This event occurred during the 2013 fiscal year, and accounted for more than half of the SAIDI result for the diesel/gas communities, as shown in Figure 6 and Figure 7. This event did not impact transmission reliability statistics, as Nahanni Butte's generating plant and distribution system are directly connected.

NTPC purchases electricity from Esso for distribution in the community of Norman Wells. Outages affecting the supply line from Esso's facility to NTPC's substation have been categorized as "transmission" caused outages. This is the only location within the diesel/gas communities group where transmission outages may occur.

Table 11: Service Continuity Results for NTPC Customers on Diesel / Gas Systems (Including Most Prominent Events)

April 01, 2015 to March 31, 2016 6316 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.02	0.33	2.14	0.02	0.00	0.25	0.00	0.01	0.00	0.00	2.77
SAIFI	0.15	0.25	6.10	0.04	0.00	0.23	0.03	0.09	0.16	0.00	7.05
April 01, 2014 to March 31, 2015 6291 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.16	0.02	2.23	0.00	0.00	0.20	0.01	0.03	0.00	0.07	2.73
SAIFI	0.71	0.11	8.02	0.02	0.01	0.19	0.10	0.04	0.02	0.10	9.32
April 01, 2013 to March 31, 2014 6261 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.01	0.05	1.27	0.00	0.00	0.01	0.37	0.00	0.00	0.01	1.72
SAIFI	0.09	0.07	6.16	0.01	0.00	0.01	0.41	0.00	0.18	0.06	6.99
April 01, 2012 to March 31, 2013 6453 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.41	0.03	1.50	0.02	0.03	0.12	0.00	3.18	0.07	0.02	5.39
SAIFI	0.50	0.08	7.19	0.01	0.12	0.11	0.08	0.01	0.02	0.11	8.23
April 01, 2011 to March 31, 2012 6491 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.02	0.18	3.79	0.08	0.00	0.10	0.29	0.00	0.01	0.18	4.64
SAIFI	0.10	0.08	8.66	0.00	0.00	0.02	0.13	0.00	0.03	0.46	9.49

Table 12: Generation Cause Contributions to Loss of Supply Interruptions for NTPC Customers on Diesel / Gas Systems (Including Most Prominent Events)

April 01, 2015 to March 31, 2016 6316 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.07	0.47	0.24	1.13	0.08	0.13	0.00	2.12
SAIFI	0.05	0.00	0.85	0.91	0.93	1.85	1.17	0.19	0.00	5.96
April 01, 2014 to March 31, 2015 6291 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.08	0.00	0.17	0.14	0.86	0.75	0.17	0.04	0.02	2.22
SAIFI	0.78	0.00	1.54	0.24	1.48	2.83	0.63	0.32	0.10	7.93
April 01, 2013 to March 31, 2014 6261 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.01	0.00	0.34	0.08	0.15	0.38	0.01	0.16	0.14	1.27
SAIFI	0.16	0.00	1.58	1.04	0.56	1.70	0.21	0.36	0.55	6.16
April 01, 2012 to March 31, 2013 6453 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.04	0.00	0.35	0.09	0.26	0.31	0.05	0.19	0.18	1.48
SAIFI	0.36	0.00	1.85	0.29	1.91	0.66	0.66	0.75	0.63	7.10
April 01, 2011 to March 31, 2012 6491 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.03	0.00	0.77	0.99	0.49	1.16	0.13	0.05	0.17	3.79
SAIFI	0.09	0.00	2.77	0.53	2.36	1.51	1.11	0.07	0.23	8.66

Table 13: Generation Cause Contributions to Loss of Supply Interruptions for NTPC Customers on Diesel / Gas Systems (Excluding Most Prominent Events)

April 01, 2015 to March 31, 2016 6316 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.07	0.47	0.24	1.13	0.08	0.13	0.00	2.12
SAIFI	0.05	0.00	0.85	0.91	0.93	1.85	1.17	0.19	0.00	5.96
April 01, 2014 to March 31, 2015 6291 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.08	0.00	0.17	0.14	0.86	0.75	0.17	0.04	0.02	2.22
SAIFI	0.78	0.00	1.54	0.24	1.48	2.83	0.63	0.32	0.10	7.93
April 01, 2013 to March 31, 2014 6261 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.01	0.00	0.34	0.08	0.15	0.38	0.01	0.16	0.14	1.27
SAIFI	0.16	0.00	1.58	1.04	0.56	1.70	0.21	0.36	0.55	6.16
April 01, 2012 to March 31, 2013 6453 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.04	0.00	0.35	0.09	0.26	0.31	0.05	0.19	0.18	1.48
SAIFI	0.36	0.00	1.85	0.29	1.91	0.66	0.66	0.75	0.63	7.10
April 01, 2011 to March 31, 2012 6491 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.03	0.00	0.77	0.99	0.49	1.16	0.13	0.05	0.17	3.79
SAIFI	0.09	0.00	2.77	0.53	2.36	1.51	1.11	0.07	0.23	8.66

Table 14: Transmission Cause Contributions to Loss of Supply Interruptions for NTPC Customers on Diesel / Gas Systems

April 01, 2015 to March 31, 2016 6316 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02
SAIFI	0.05	0.00	0.00	0.00	0.00	0.00	0.09	0.14
April 01, 2014 to March 31, 2015 6291 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01
SAIFI	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.09
April 01, 2013 to March 31, 2014 6261 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2012 to March 31, 2013 6453 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
April 01, 2011 to March 31, 2012 6491 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

NUL Supply Point Availability

Snare System

NTPC provides generation and transmission for NUL-served customers within the City of Yellowknife. The Snare System includes six hydro generating plants, three stand-by diesel plants available to supply customers within the City of Yellowknife, and two transmission lines owned and operated by NTPC. NUL owns and operates the distribution system within the City of Yellowknife.

RESULTS

Figure 8: Service Continuity Results by Fiscal Year for NTPC interruptions to NUL Customers on the Snare System (Including Most Prominent Events)

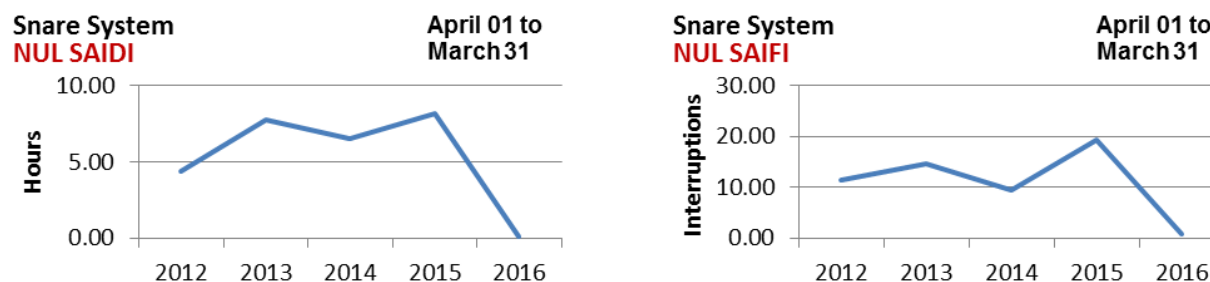
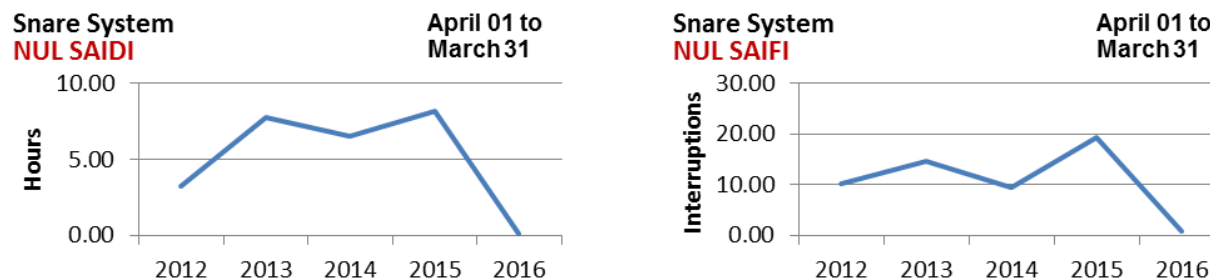


Figure 9: Service Continuity Results by Fiscal Year for NTPC Interruptions to NUL Customers on the Snare System (Excluding Most Prominent Events)



INTERPRETATION

Low water conditions on NTPC's Snare and Bluefish hydro systems required the continuous operation of diesel generators between July 2014 and April 2016. During this period, approximately 35% of all electrical energy delivered to the Snare System originated with diesel generation, compared to approximately 2% in a typical year. This change in generating source had a significant impact on customer interruptions, resulting in 5-year lows in both SAIDI and SAIFI.

Forest fire activity in the vicinity of NTPC's transmission lines contributed 3.26 hours to SAIDI and 6.46 interruptions to SAIFI for NUL customers during the summer of 2014, producing 5-year highs for outage indicators on this system in the 2014-15 fiscal year.

In the 2011-12 fiscal year, customer interruptions resulting from the collision of a military helicopter with the Snare transmission line in February 2012 are identified as an MPE. This event contributed approximately 25% of the annual SAIDI for NUL customers on the Snare System in 2012.

Table 15: Service Continuity Results for NTPC Supply to NUL Customers on the Snare System (Including Most Prominent Events)

April 01, 2015 to March 31, 2016 8594 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.14
SAIFI	0.00	0.00	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.86
April 01, 2014 to March 31, 2015 8422 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	8.12	0.00	0.00	0.00	0.00	0.00	0.08	0.00	8.20
SAIFI	0.00	0.00	19.07	0.00	0.00	0.00	0.00	0.00	0.28	0.00	19.35
April 01, 2013 to March 31, 2014 8423 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.26	0.00	6.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.18
SAIFI	0.62	0.00	12.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.72
April 01, 2012 to March 31, 2013 8254 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	5.98	0.00	0.00	0.00	0.00	0.00	0.00	1.75	7.73
SAIFI	0.00	0.00	13.08	0.00	0.00	0.00	0.00	0.00	0.00	1.57	14.65
April 01, 2011 to March 31, 2012 8709 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.03	0.00	4.23	0.00	0.00	0.00	0.07	0.00	0.00	0.04	4.37
SAIFI	0.22	0.00	11.38	0.00	0.00	0.00	0.36	0.00	0.00	0.27	12.22

Table 16: Service Continuity Results for NTPC Supply to NUL Customers on the Snare System (Excluding Most Prominent Events)

April 01, 2015 to March 31, 2016 8594 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.14
SAIFI	0.00	0.00	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.86
April 01, 2014 to March 31, 2015 8422 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	8.12	0.00	0.00	0.00	0.00	0.00	0.08	0.00	8.20
SAIFI	0.00	0.00	19.07	0.00	0.00	0.00	0.00	0.00	0.28	0.00	19.35
April 01, 2013 to March 31, 2014 8423 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.26	0.00	6.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.18
SAIFI	0.62	0.00	12.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.72
April 01, 2012 to March 31, 2013 8254 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	5.98	0.00	0.00	0.00	0.00	0.00	0.00	1.75	7.73
SAIFI	0.00	0.00	13.08	0.00	0.00	0.00	0.00	0.00	0.00	1.57	14.65
April 01, 2011 to March 31, 2012 8709 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.03	0.00	3.14	0.00	0.00	0.00	0.07	0.00	0.00	0.04	3.27
SAIFI	0.22	0.00	10.21	0.00	0.00	0.00	0.36	0.00	0.00	0.27	11.06

Table 17: Generation Cause Contributions to Loss of Supply Interruptions for NUL Customers on the Snare System²

April 01, 2015 to March 31, 2016 8594 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
SAIFI	0.00	0.00	0.22	0.00	0.00	0.03	0.00	0.00	0.00	0.26
April 01, 2014 to March 31, 2015 8422 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.01	0.00	0.48	0.00	0.92	0.00	0.03	0.00	0.00	1.44
SAIFI	0.21	0.00	2.19	0.00	2.00	0.00	0.28	0.00	0.00	4.68
April 01, 2013 to March 31, 2014 8423 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.13	0.00	0.53	0.01	0.00	0.02	0.00	0.00	0.00	0.70
SAIFI	0.61	0.02	0.96	0.03	0.02	0.08	0.00	0.00	0.00	1.72
April 01, 2012 to March 31, 2013 8254 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.01	0.00	0.51	0.00	0.01	0.02	0.00	0.00	0.54
SAIFI	0.00	0.10	0.02	1.20	0.00	0.09	0.16	0.00	0.00	1.57
April 01, 2011 to March 31, 2012 8709 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.05	0.02	0.30	0.00	0.00	0.00	0.00	0.37
SAIFI	0.00	0.00	0.45	0.14	0.84	0.02	0.00	0.00	0.00	1.44

² The number of NUL customers prior to 2011-12 is estimated.

**Table 18: Transmission Cause Contributions to Loss of Supply Interruptions for NUL Customers on the Snare System
(Including Most Prominent Events)**

April 01, 2015 to March 31, 2016 8594 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.11
SAIFI	0.00	0.00	0.46	0.00	0.00	0.00	0.00	0.46
April 01, 2014 to March 31, 2015 8422 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	1.96	3.26	0.62	0.00	0.79	6.63
SAIFI	0.00	0.00	3.72	6.46	1.86	0.00	1.94	13.99
April 01, 2013 to March 31, 2014 8423 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	2.33	1.97	0.00	0.01	0.01	0.08	4.40
SAIFI	0.00	1.11	3.85	0.00	0.09	0.09	0.75	5.89
April 01, 2012 to March 31, 2013 8254 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	1.39	0.72	3.24	0.00	0.09	0.00	0.00	5.44
SAIFI	5.10	0.90	5.27	0.00	0.24	0.00	0.00	11.50
April 01, 2011 to March 31, 2012 8709 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.70	0.32	1.18	0.00	0.00	0.00	1.66	3.86
SAIFI	4.31	0.96	2.53	0.00	0.00	0.00	2.13	9.93

**Table 19: Transmission Cause Contributions to Loss of Supply Interruptions for NUL Customers on the Snare System
(Excluding Most Prominent Events)**

April 01, 2015 to March 31, 2016 8594 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.11
SAIFI	0.00	0.00	0.46	0.00	0.00	0.00	0.00	0.46
April 01, 2014 to March 31, 2015 8422 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	1.96	3.26	0.62	0.00	0.79	6.63
SAIFI	0.00	0.00	3.72	6.46	1.86	0.00	1.94	13.99
April 01, 2013 to March 31, 2014 8423 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	2.33	1.97	0.00	0.01	0.01	0.08	4.40
SAIFI	0.00	1.11	3.85	0.00	0.09	0.09	0.75	5.89
April 01, 2012 to March 31, 2013 8254 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	1.39	0.72	3.24	0.00	0.09	0.00	0.00	5.44
SAIFI	5.10	0.90	5.27	0.00	0.24	0.00	0.00	11.50
April 01, 2011 to March 31, 2012 8709 Customers								
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.70	0.32	1.18	0.00	0.00	0.00	0.56	2.76
SAIFI	4.31	0.96	2.53	0.00	0.00	0.00	0.96	8.77

Table 20: NTPC SAIDI Results at Individual NUL Breakers (Including Most Prominent Events)

April 1 to March 31

	2012	2013	2014	2015	2016
7000s 52-501	4.75	8.62	6.65	5.48	0.03
7000s 52-502	4.44	9.00	7.07	6.25	0.13
7000s 52-504	6.11	10.52	7.32	6.62	0.12
7000s 52-505	5.33	8.68	6.17	6.25	0.00
7001s 52-501	5.30	6.62	6.17	8.72	0.25
7001s 52-502	4.23	6.98	6.33	9.58	0.00
7001s 52-504	5.30	8.83	6.57	9.48	0.25
7001s 52-505	4.23	7.87	7.12	9.95	0.00
7002s 52-520	4.25	7.97	6.67	7.18	0.00
7002s 52-521	5.78	8.72	7.07	7.25	0.30
7002s 52-523	6.08	10.33	7.57	8.65	0.38
7002s 52-524	N/A	2.62	7.28	10.22	0.00
400s	4.35	0.73	1.37	0.82	0.00

Table 21: NTPC SAIDI Results at Individual NUL Breakers (Excluding Most Prominent Events)

April 1 to March 31

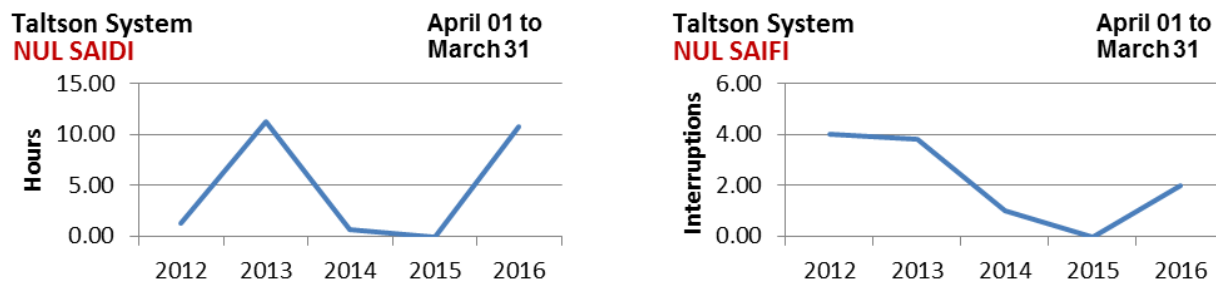
	2012	2013	2014	2015	2016
7000s 52-501	3.65	8.62	6.65	5.48	0.03
7000s 52-502	3.58	9.00	7.07	6.25	0.13
7000s 52-504	3.91	10.52	7.32	6.62	0.12
7000s 52-505	3.72	8.68	6.17	6.25	0.00
7001s 52-501	3.85	6.62	6.17	8.72	0.25
7001s 52-502	3.42	6.98	6.33	9.58	0.00
7001s 52-504	4.40	8.83	6.57	9.48	0.25
7001s 52-505	3.75	7.87	7.12	9.95	0.00
7002s 52-520	3.53	7.97	6.67	7.18	0.00
7002s 52-521	4.07	8.72	7.07	7.25	0.30
7002s 52-523	4.10	10.33	7.57	8.65	0.38
7002s 52-524		2.62	7.28	10.22	0.00
400s	0.40	0.73	1.37	0.82	0.00

Taltson System

NTPC provides generation and transmission for NUL-serviced customers within the Town of Hay River. The Taltson System includes one hydro generating plant and a transmission line owned and operated by NTPC. NUL owns and operates a transmission line from Pine Point to Hay River, and a stand-by diesel plant and distribution system within the Town of Hay River.

RESULTS

Figure 10: Service Continuity Results by Fiscal Year for NTPC Interruptions to NUL Customers on the Taltson System³



³ The Taltson system has not experienced any interruptions identified as Most Prominent Events between April 1, 2011 and March 31, 2016. As a result, data including and excluding Most Prominent Events will not be presented separately for this system.

INTERPRETATION

Interruption time due to the annual maintenance shutdown of the Taltson hydro plant has not been included in these statistics. During this planned maintenance, NUL operates its own generating station to supply customers in Hay River.

Table 22: Service Continuity Results for NTPC Supply to NUL Customers on the Taltson System

April 01, 2015 to March 31, 2016 1978 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	10.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.75
SAIFI	0.00	0.00	2.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00
April 01, 2014 to March 31, 2015 1976 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2013 to March 31, 2014 1955 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.63
SAIFI	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00
April 01, 2012 to March 31, 2013 1947 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	11.01	0.00	0.00	0.00	0.26	0.00	0.00	0.00	11.28
SAIFI	0.00	0.00	2.99	0.00	0.00	0.00	0.99	0.00	0.00	0.00	3.98
April 01, 2011 to March 31, 2012 1930 Customers											
	Unknown/ Other	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environment	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.28
SAIFI	0.00	0.00	4.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00

Table 23: Generation Cause Contributions to Loss of Supply Interruptions for NUL Customers on the Taltson System

April 01, 2015 to March 31, 2016 1978 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2014 to March 31, 2015 1976 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2013 to March 31, 2014 1955 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2012 to March 31, 2013 1947 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.21
SAIFI	0.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.99
April 01, 2011 to March 31, 2012 1930 Customers										
	Unknown	Plant Structures	Power Generation Systems	Electrical Power Systems	Instrumentation and Control	Plant Auxiliary Processes	Human Element	Planned	External Conditions	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 24: Transmission Cause Contributions to Loss of Supply Interruptions for NUL Customers on the Taltson System

April 01, 2015 to March 31, 2016		1978 Customers						
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	10.75	10.75
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	2.00	2.00
April 01, 2014 to March 31, 2015		1976 Customers						
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
April 01, 2013 to March 31, 2014		1955 Customers						
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.63
SAIFI	1.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00
April 01, 2012 to March 31, 2013		1947 Customers						
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	2.67	0.00	0.00	0.00	0.00	0.00	8.13	10.80
SAIFI	1.00	0.00	0.00	0.00	0.00	0.00	1.00	2.00
April 01, 2011 to March 31, 2012		1930 Customers						
	Unknown	Defective Equipment	Adverse Weather	Adverse Environment	System Condition	Human Element	Foreign Interference	Total
SAIDI	0.00	0.00	1.28	0.00	0.00	0.00	0.00	1.28
SAIFI	0.00	0.00	4.00	0.00	0.00	0.00	0.00	4.00

Appendix D

Snare Forks Major Project Permit Application

NORTHWEST TERRITORIES POWER CORPORATION

APPLICATION FOR A PROJECT PERMIT

SNARE FORKS HYDRO UNIT 1 OVERHAUL

Northwest Territories Power Corporation
Major Project Permit Application
Snare Forks Hydro Unit 1 Overhaul – June 2016

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Northwest Territories Power Corporation
Major Project Permit Application
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Introduction

The Northwest Territories Power Corporation (“NTPC” or “Corporation”) hereby applies to the Northwest Territories Public Utilities Board (“Board”) pursuant to Sections 23 and 54 of the **Public Utilities Act**, R.S.N.W.T 1988, c. 24 (Supp) for a project permit and further or other relief as the Board considers advisable respecting the Snare Forks Hydro Unit 1 Overhaul Project (the “Project”). The Project involves addressing known deficiencies at the facility to maintain system reliability and integrity. Total project costs are estimated at \$7.9M.

The application provides a summary of the proposed project for Board. A business case for the Project is included in Attachment A.

Substantiated Need for the Project

The North Slave electrical system requires up 36 MW of generating capacity for winter peaks, of which 32MW can be reliably supplied from 8 hydroelectric units installed on the Snare and Bluefish rivers. During most of the year, energy for the North Slave System can be supplied from the hydro units, which minimizes the fuel costs associated with diesel generation. Hydroelectric generation also reduces greenhouse gas emissions compared to using diesel generation.

NTPC retained an engineering consultant to perform an inspection of Snare Forks unit 1 in 2014. The consultant identified deficiencies that could result in lengthy forced outages if not addressed. The main issue is that the turbine running clearances and vertical Unit alignment are poor and need to be corrected to ensure long term reliable operation. Secondary issues identified by the consultant include:

- A bent wicket gate which causes more water leakage and wicket gate damage when shutdown and more wear on brakes.
- Turbine shaft seal stainless steel journal is damaged and needs replacement.
- Wicket gate bushing clearances are difficult to measure and may need replacing.
- The generator winding has not been tested recently but to ensure there is reliable operation for another 40 years it would be replaced during a long outage on the turbine.

The failure of one of the Snare Forks units would mean the loss of 3.5MW (the units are generally not run at full capacity because of the need to provide frequency control). In addition, to avoid spilling, Snare Rapids would be reduced by 1MW and Snare Falls and Snare Cascades would be reduced by 0.5MW each. This results in a loss of 5.5MW.

Snare Forks hydro units are the preferred units to use to support the North Slave Electrical System frequency due to their most downstream location and the size of the headpond. If other units are used at other plants, it will impact the water management of the two river systems, which will lower hydro-electric generation and require more diesel generation to replace it.

Any outage to hydroelectric units needs to be scheduled for the summer/fall period to minimize the need for diesel generation. The cost of running hydro units to failure results in longer

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Snare Forks Hydro Unit 1 Overhaul – June 2016

outages to repair and replace components and much higher costs for repairing collateral damage, expedited parts delivery and replacement diesel power.

Project Description

The proposed project entails the overhaul the Snare Forks Unit 1 to address known deficiencies and maintain system reliability and integrity. The project will be completed in the summer months during a time period when electricity demand has historically been lower in an effort to minimize diesel generation. The main components to be addressed in the planned outage to overhaul the unit are:

- Intake Gate overhaul with new seals and inspect/repair trash racks
- Penstock inspection and coating repair
- Generator stator winding replaced. Rotor Poles Inspected and repaired as needed.
- Turbine wicket gate and linkage bushings replaced and repair/replace bent wicket gate
- Correct vertical alignment of generator and turbine
- Correct other problems as found during overhaul work.

The overhaul of the unit 1 at the Snare Forks plant will provide the following key benefits to the Corporation and its customers:

- Reliability - Completing the overhaul helps maintain system reliability. The existing deficiencies have the potential to result in a lengthy and costly unplanned outage.
- Avoid diesel fuel costs associated with unplanned outages – Diesel generation is used to generate power when the hydro units are shut down for repairs and overhauls. Delaying the overhaul of the G1 unit will result in further deterioration of the asset and increase the length of time of the overhaul and shut down period, which will increase the usage of costly diesel generation.
- Reduced emissions – Implementation of this option will result in less unit downtime and reduce the amount of greenhouse gas emissions produced by diesel generation.
- Minimizing capital costs – Completing the overhaul as soon as possible will limit the deterioration of the asset and reduce the total capital cost. Continued wear of the parts could lead to additional damage to the unit and may cause a serious failure forcing a shutdown of the asset, which would quickly escalate the cost of the overhaul.

Further information is provided in the project business case in Attachment A.

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Grounds in Support for Project

Public Need for the Project

The Snare Forks hydroelectric Unit 1 is 40 years old and has not had any major overhaul work done for over a decade. The project is required to ensure the reliability of the system and to avoid costly diesel fuel costs associated with a potential future unplanned outage. Undertaking the project will ensure the Corporation can continue to provide safe, reliable, cost effective generation on the Snare system. The project will provide benefits to ratepayers in avoided diesel costs and improved reliability.

Reliability of Public Utility

Under the **NTPC Act** one of the objectives of the Corporation is to ensure a continuous and reliable supply adequate for the needs and future development of the Territories. The deficiencies identified at Snare Forks unit 1 should be addressed to ensure reliability of the system.

Rate Impact

The project will not have any impact on rates until the time of the next General Rate Application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 60 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$7.867M
- Amortization rate of 1.67%
- Return on Ratebase of 7.18%
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 1.87%.

Conclusion

The Corporation has identified a number of deficiencies at Snare Forks Unit 1 that should be addressed in order to maintain safe, reliable, cost effective service. Delaying the project puts system reliability at risk and increases the chance of a costly unplanned outage. Based on the foregoing, NTPC respectfully requests that the Board approve this application by issuing a project permit pursuant to Sections 23 and 54 of the Public Utilities Act in an amount of \$7.9 million.

Northwest Territories Power Corporation
Major Project Permit Application
Snare Forks Hydro Unit 1 Overhaul – June 2016

ATTACHMENT A:
BUSINESS CASE
SNARE FORKS HYDRO UNIT 1 OVERHAUL

Northwest Territories Power Corporation
Major Project Permit Application
Snare Forks Hydro Unit 1 Overhaul – June 2016

NEED FOR PROJECT

NTPC is proposing to undertake a project to overhaul the Snare Forks Hydroelectric Unit 1 to address known deficiencies in order to maintain system reliability and integrity. An engineering consultant firm performed an inspection of unit 1 in August of 2014. The consultant identified deficiencies that could result in lengthy forced outages if not addressed. The main issue is that the turbine running clearances and vertical Unit alignment are poor and need to be corrected to ensure long term reliable operation. The secondary issues identified are as follows:

- A bent wicket gate which causes more water leakage and wicket gate damage when shutdown and more wear on brakes.
- Turbine shaft seal stainless steel journal is damaged and needs replacement.
- Wicket gate bushing clearances are difficult to measure and may need replacing.
- The generator winding has not been tested recently but to ensure there is reliable operation for another 40 years it would be replaced during a long outage on the turbine.

The North Slave electrical system requires up to 36 MW of generating capacity for winter peaks, of which 32MW can be reliably supplied from 8 hydroelectric units installed on the Snare and Bluefish rivers. During most of the year, energy for the North Slave System can be supplied from the hydro units, which minimizes the fuel costs associated with diesel generation. Hydroelectric generation also reduces greenhouse gas emissions compared to using diesel generation.

The failure of one of the Snare Forks units would mean the loss of 3.5MW (they are generally not run at full capacity because of the need to provide frequency control). In addition, to avoid spilling, Snare Rapids would be reduced by 1MW and Snare Falls and Snare Cascades would be reduced by 0.5MW each. This results in a loss of 5.5MW. This translates into the following approximate additional cost of operation:

- \$40k per day
- \$1.2M per month
- \$3.6M for a 3 month outage

Snare Forks hydro units are the preferred units to use to support the North Slave Electrical System frequency due to their most downstream location and the size of the headpond. If other units are used at other plants, it will impact the water management of the two river systems, which will lower hydro-electric generation and require more diesel generation to replace it.

Any outage to hydroelectric units needs to be scheduled for the summer/fall period to minimize the need for diesel generation. The cost of running hydro units to failure results in longer outages to repair and replace components and much higher costs for repairing collateral damage, expedited parts delivery and replacement diesel power.

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BACKGROUND

The Snare Hydro system is comprised of four plants on the Snare River located approximately 145km northwest of Yellowknife. The plants were constructed between 1946 and 1996 as noted below:

- Snare Rapids (1946)
- Snare Falls (1960)
- Snare Cascades (1996)
- Snare Forks (1976)

The Snare Forks generating station was built and commissioned by the Northern Canada Power Commission in 1976. The generating station is located 10 km downstream of Snare Cascades. It is the plant furthest downstream in the cascade and discharges into Strutt Lake. The power plant contains two units producing 4.5 MW each (14 % of reliable generation), which are used in isochronous mode to support the frequency of the North Slave Electrical system. This duty requires frequent changes to wicket gate position and more stop start operations to the units which can cause more “wear and tear” on the units. These two units are the preferred ones to use of the 8 hydro-electric units in the North Slave system due to size and hydraulic configuration of the river.



Snare Forks (SK) Power Plant.

Snare Forks units are a 1928 vintage design obtained from Ontario hydro and installed in 1976 in their current location. The turbine runners were replaced in an overhaul in 1986/87 to increase the efficiency of producing electricity and uses of stainless steel overlay to prevent cavitation damage. The exciters for both Unit 1 and Unit 2 were upgraded in the last 5 years. The governors were upgraded in 2014 for both machines to help improve the frequency stability in the North Slave Electrical System.

The Snare Forks Unit 1 unit has not had any major overhauls in the past 10 to 15 years. In 2015, new electronic governors were installed on the two Snare Forks generating units. Hydro Tech Inc. (engineering consultant firm) completed a detailed inspection in 2014 of Unit 1 and its associated equipment. The inspection identified a number of major and minor deficiencies that should be corrected as soon as possible.

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Major Project Permit Application
Snare Forks Hydro Unit 1 Overhaul – June 2016

ANALYSIS OF OPTIONS

Option 1: Do Nothing

There have not been any significant capital expenditures completed on the unit 1 over the last 10 to 15 years except for the recent installation of the two electronic governors. Given the unit's deficiencies and the advanced age (40 years) of its major components, it is not advisable NTPC ignore the issues and do nothing. Failure of the unit could result in a costly unscheduled shutdown. Therefore, the continuation of the status quo with respect to unit 1 is not a viable approach.

Option 2: Overhaul Snare Forks Unit 1 Estimated Costs: \$7,867,000

This option entails the overhaul the Snare Forks Unit 1 to address known deficiencies and maintain system reliability and integrity. The project will be completed in the summer months during a time period when electricity demand has historically been lower in an effort to minimize diesel generation. The main components to be addressed in the planned outage to overhaul the unit are:

- Intake Gate overhaul with new seals and inspect/repair trash racks
- Penstock inspection and coating repair
- Generator stator winding replaced. Rotor Poles Inspected and repaired as needed.
- Turbine wicket gate and linkage bushings replaced and repair/replace bent wicket gate
- Correct vertical alignment of generator and turbine
- Correct other problems as found during overhaul work.

The overhaul of the unit 1 at the Snare Forks plant will provide the following key benefits to the Corporation and its customers:

- Reliability - Completing the overhaul helps maintain system reliability. The existing deficiencies have the potential to result in a lengthy and costly unplanned outage.
- Avoid diesel fuel costs associated with unplanned outages – Diesel generation is used to generate power when the hydro units are shut down for repairs and overhauls. Delaying the overhaul of the G1 unit will result in further deterioration of the asset and increase the length of time of the overhaul and shut down period, which will increase the usage of costly diesel generation. The cost of the diesel fuel associated with a 3 month outage is estimated at \$3.6 million.
- Reduced emissions – Implementation of this option will result in less unit downtime and reduce the amount of greenhouse gas emissions produced by diesel generation.
- Minimizing capital costs – Completing the overhaul as soon as possible will limit the deterioration of the asset and reduce the total capital cost. Continued wear of the parts could lead to additional damage to the unit and may cause a serious failure forcing a shutdown of the asset, which would quickly escalate the cost of the overhaul.

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COST ESTIMATES**Table 1 – Budget Estimates****Planning**

Description	2017/18
Payroll Regular	17,000
Payroll Fringe Benefits	6,000
Consultants Lump Sum	105,000
Contingency	25,000
Total	\$153,000

Construction

Description	2018/19
Payroll Regular	202,500
Payroll Overtime	81,000
Payroll Fringe Benefits	71,000
Consultants Lump Sum	525,000
Contractors Lump Sum	3,800,000
Fuel for type 5 and 6 jobs	1,200,000
Contingency	1,176,000
Total	\$7,055,500

Project Estimated Costs

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$153,000	\$4,700	\$13,800	\$171,500
2018/19	\$7,055,500	\$4,871	\$635,000	\$7,695,371
Total Project Cost				\$7,866,871

Northwest Territories Power Corporation
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RATE IMPACTS

The project will not have any impact on rates until the time of the next general rate application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 60 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$7.867M
- Amortization rate of 1.67%
- Return on Ratebase of 7.18%
- Allocation costs to Snare Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Snare Zone customers is estimated at 1.87%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$7,867	\$9,834	\$11,800	\$15,734
Amortization Period (Approx. Years)	60	60	60	60
GRA Approved Return on Ratebase	7.18%	7.18%	7.18%	7.18%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$131	\$164	\$197	\$263
Return on Ratebase (\$000)	\$565	\$706	\$847	\$1,130
Sub-Total: Revenue Requirement Increase (\$000)	\$696	\$870	\$1,044	\$1,392
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$696	\$870	\$1,044	\$1,392
Snare Zone Revenue Requirement (\$000)	\$37,174	\$37,174	\$37,174	\$37,174
Average Percentage Rate Increase	1.87%	2.34%	2.81%	3.75%

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Major Project Permit Application
Snare Forks Hydro Unit 1 Overhaul – June 2016

SUMMARY OF BUSINESS CASE RATIONALE

The Snare Forks hydroelectric Unit 1 is 40 years old and has not had any major overhauls for over a decade. An inspection was completed on the two Snare Forks generating units in 2014, which identified a number of major and minor deficiencies that needed to be corrected by overhauling the unit. The condition of the unit will continue to degrade and a more serious failure could occur resulting in higher operational and capital costs, reduced asset reliability and increased emissions from diesel generation.

Across the Northwest Territories, NTPC's existing facilities and assets such as Snare Forks Unit 1 are aging and therefore need to be upgraded to meet the ongoing demand for reliable electricity generation. Investing in NTPC's facilities means that customers can continue to enjoy reliable, clean power from hydro generating stations built decades ago. In addition, hydroelectric infrastructure investments will help to keep electricity rates relatively affordable in the NWT. NTPC can reduce the need to build new infrastructure, and the corresponding costs for new facilities, by investing in and maintaining the existing assets in good working order.

RECOMMENDATION

It is recommended the Corporation proceed with the Snare Forks overhaul of hydro Unit 1 as outlined in option #2. The total costs to complete the project are estimated to be \$7.87M.

Northwest Territories Power Corporation
Major Project Permit Application
Snare Forks Hydro Unit 1 Overhaul – June 2016

Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page #11.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>

Appendix E
Intelligent Metering Major Project Permit
Application

NORTHWEST TERRITORIES POWER CORPORATION

APPLICATION FOR A PROJECT PERMIT

IMH METERING UPGRADE

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ATTACHMENTS: Business Case

Introduction

The Northwest Territories Power Corporation ("NTPC" or "Corporation") hereby applies to the Northwest Territories Public Utilities Board ("Board") pursuant to Sections 23 and 54 of the **Public Utilities Act**, R.S.N.W.T 1988, c. 24 (Supp) for a project permit and further or other relief as the Board considers advisable respecting the IMH Metering Upgrade. The Project involves installing new metering in all communities in advance of recertification/replacement requirements for existing meters in the larger communities and to improve metering performance in smaller communities. Total project costs are estimated at \$5.0M.

The application provides a summary of the proposed project for Board. Business cases for the Project are included in Attachment A.

Substantiated Need for the Project

NTPC currently relies on two methods for recording and entering revenue meter readings into the billing system. In larger communities NTPC uses an automatic meter reading system which receives the meter read approximately once per day transmitted over a power line carrier. In smaller communities, NTPC require staff to physically go to each meter and record the meter reading. In both cases NTPC staff, are required to install or remove the meter when a customer moves in, moves out or is disconnected for failing to pay their account.

NTPC installed Hunt Technologies automatic meter reading system in the larger communities between 1996 and 2004. This system uses the electrical power lines to carry an electronic signal from the customer's meter to a receiver in the power plant to record energy consumption. This technology allowed NTPC to access meter readings electronically and eliminated the need for comprehensive manual meter reading by the line crew.

This meter reading system had many years of successful operation but now has several issues:

- Recertification - The meters installed now require re-certification to be compliant with Measurement Canada requirements. Recertification of the current meters would be costly and have significant operational issues as they must be brought out of service to be certified.
- Manual meter reading - Degradation in signal quality has resulted in up to the need to provide manual reads each month
- Technology obsolescence - Meters which work on this technology are no longer available and the supplier no longer supports this technology
- Meter failures – The current meters in operation are starting to fail with more meters expected to fail over time. This problem has become critical in Fort Smith. A separate case has been prepared for that community regarding replacement of the current meters with new intelligent meters.
- Revenue Losses - As meters fail and customers utilize power, the energy usage is not recognized by the meter, which results in a loss of revenue as the usage is not captured and there is no practical way to assess the customer's energy usage.

All smaller communities rely on plant superintendents to physically read each meter every month, record the read on a meter reading sheet, sends the sheet into the billing clerk who manually enters the reads.

In 2016 NTPC initiated an evaluation project in Jean Marie River to evaluate the Landis & Gyr, Gridstream RF 2-way meter system. This project is now operating successfully. This product has a strong track record with successful operation in other extreme weather areas including Edmonton, Northern Quebec, and Nunavut.

Project Description

The Project involves replacing the existing metering in all of the Corporation's communities with the Gridstream RF 2-way meter system, with the exception of Jean Marie River where the Gridstream metering is already operating successfully.

This technology revolves around 2 components. The physical infrastructure consists of meters, collectors, and routers and the software component which records and inquires on the data. A brief description of the new 2-way metering system and its key components are listed below:

- Meters – digital meters which provide remote connect/disconnect/limiting capabilities. Meters transmit an RF (radio frequency) signal for control and to report data.
- Routers - Receive the RF signal and repeat the signal to other routers or the collector.
- Collectors – receive the RF signal and send the data to the database.
- Command Center Software - controls meters, records meter information, reports on individual or grouped meter data and provides alerts on meter and distribution system disruptions.
- SmartWorks Software – provides meter management throughout the Corporation and an external customer portal of account meter readings and energy usage.

Based on the capabilities of the new system, the Corporation and its customers would realize a number of benefits including:

Customer Benefits

- Consistently accurate actual, not estimated, usage on power bills.
- Energy consumption information available through portal.
- Can assist customers in demand side management.
- In home electricity monitoring devices are available.
- Better move in/move out experience.
- Beyond the meter devices available to monitor and control household devices.

Customer Service and Billings Benefits

- Accelerates billing process and accelerates payment receipt reducing working capital.
- Better, more informed response to billing inquiries.
- Reduces steps required to process service orders.
- Allows for easier and efficient management of collection process.
- Identifies energy theft and meter tampering.

- Allows for 3rd party value added services such as water meter reading.

Operations Benefits

- Eliminates the time and physical risks of manual reading.
- Local operators are separated from collection disconnect/limiting conflicts.
- Reduces meter access issues.
- Provides accurate geographical display of meter location.
- Reports on self-generation.

Transmission & Distribution Benefits

- Provides detailed information for distribution load management.
- Allows for immediate outage detection and locating.
- Data available and reports produced for power quality / voltage monitoring.
- Facilitates system diagnostics and reporting.

Asset Management and Engineering Benefits

- Assists with community load profiling and forecasting

Table 1 provides the estimated budget to install the metering upgrade in all communities at \$4.9 million. The project budget is close to the \$5 million requirement for a major project permit and therefore the Corporation is requesting that the permit be granted in the amount of \$5 million.

Table 1
Estimated Project Budget

Description	Total
Payroll Regular	360,000
Payroll Overtime	19,000
Payroll Fringe Benefits	126,000
Meters	2,400,000
Computer Software	561,000
Contingency	689,000
Total Base Project Estimate	4,155,000

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
Total	\$4,155,000	\$0	\$745,000	\$4,900,000

Further information on the comparisons of options considered is provided in project business cases in Attachment A.

Grounds in Support for Project*Public Need for the Project*

The Corporation requires accurate metering in order to ensure customers are fairly charged for the electricity they consume. Improved metering technology and metering accuracy also facilitates improved customer relationships.

Reliability of Public Utility

The accuracy and reliability of the Corporation's metering system is of considerable importance to ensuring the Corporation collects the revenue required to maintain financial stability. The current automated metering system in place in larger communities will require replacement/recertification in the near term. This provides an opportunity to upgrade the Corporation's metering technology to a proven, robust technology in all communities which will provide a number of benefits to the Corporation and its customers.

Rate Impact

The project will not have any impact on rates until approved for inclusion in rates as part of a general rate application. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 21 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$4.9M
- Amortization rate of 4.73%
- Return on Ratebase of 6.88%
- Allocation costs across the Corporation.

Given the above assumptions, the average rate impact of the project for customers is estimated at 0.54%.

Table 2
Rate Impact Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$4,900	\$6,125	\$7,350	\$9,800
Amortization Period (Approx. Year)	21	21	21	21
GRA Approved Return on Ratebase	6.88%	6.88%	6.88%	6.88%
Revenue Requirement Impacts				
Software License (\$000)	\$60.00	\$60.00	\$60.00	\$60.00
Amortization Expense (\$000)	\$231.77	\$289.71	\$347.66	\$463.54
Return on Ratebase (\$000)	\$337.12	\$421.40	\$505.68	\$674.24
Sub-Total: Revenue Requirement Increase (\$000)	\$628.89	\$771.11	\$913.34	\$1,197.78
Less: Estimated O&M Savings (\$000)	\$55.00	\$55.00	\$55.00	\$55.00
Total Revenue Requirement Impact (\$000)	\$573.89	\$716.11	\$858.34	\$1,142.78
Total Community Revenue Requirement (\$000)	\$105,840	\$105,840	\$105,840	\$105,840
Average % Rate Increase	0.542%	0.677%	0.811%	1.080%

Conclusion

The Corporation has a need to address the impending need to recertify or replace the existing automated metering in its larger communities. This provides an opportunity to install consistent metering across all communities. The proposed technology has been successfully implemented and operated in Jean Marie River and a number of other jurisdictions in Canada. In addition to addressing the need to recertify or replace existing metering in many communities, the proposed technology provides a number of potential benefits in improved accuracy and performance. Based on the foregoing, NTPC respectfully requests that the Board approve this application by issuing a project permit pursuant to Sections 23 and 54 of the Public Utilities Act in an amount of \$5.0 million.

ATTACHMENT A:
BUSINESS CASES
IMH METERING UPGRADE

Appendix F
Norman Wells New Plant Major Project Permit
Application

NORTHWEST TERRITORIES POWER CORPORATION

APPLICATION FOR A PROJECT PERMIT

NORMAN WELLS PLANT REPLACEMENT

Northwest Territories Power Corporation
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ATTACHMENTS: Business Case

Northwest Territories Power Corporation
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Introduction

The Northwest Territories Power Corporation (“NTPC” or “Corporation”) hereby applies to the Northwest Territories Public Utilities Board (“Board”) pursuant to Sections 23 and 54 of the **Public Utilities Act**, R.S.N.W.T 1988, c. 24 (Supp) for a project permit and further or other relief as the Board considers advisable respecting the Norman Wells Plant Replacement Project (the “Project”). The Project involves replacing the existing diesel plant in Norman Wells in order to maintain system reliability and integrity. Total project costs are estimated at \$4.6M.

The application provides a summary of the proposed project for Board review. A business case for the Project is included in Attachment A.

Substantiated Need for the Project

The existing power plant in Norman Wells was commissioned in 1961 to supply power to the town. Imperial Oil built a new power plant in the late 1990s and began to supply the power to NTPC’s standby plant. Power purchased from Imperial Oil is distributed by NTPC from the standby plant to the Town of Norman Wells. Whenever the Esso plant is shut down for routine maintenance or unforced outages, NTPC’s standby plant operates its generators and supplies power to the town.

The plant was designed so as not to disturb the permafrost under the power plant foundation. Culverts were placed on top of the permafrost ground and then a gravel pad was constructed over top of the culverts. The plant’s concrete slab foundation was then placed on top of the gravel pad. The design of the foundation would allow the permafrost to remain in the ground by leaving the ends of the culverts open during the winter and closing them in the summer. Over time, the culverts have severely rusted causing the floor of the plant to settle and completely collapse in certain areas. As a result of the rusting, sink holes were discovered under the concrete floor.

The Corporation places the diesel generators on genset pads, which are in turn placed on steel piles that provide firm support to the units. However, the floor around the pads is severely cracked and the floor sounds very hollow under foot traffic. The floor in the switchgear room has sunk by 30 mm, and the concrete floor below the wall that divides the genset bay and the switchgear bay has sunk to the degree that the wall no longer rests on the concrete floor.

The issues with the building’s foundation pose the following serious issues:

- Reliability - The instability of the foundation poses a risk to the reliability of the plant. Collapse of the foundation around the gensets would render them inoperable or potentially result in significant damage to the units.
- Safety - The foundation under the switchgear (feeder and generator breakers) is deficient and there is a risk of electrical faults that could result in unexpected electrical arc flash hazard, which places the staff at risk of serious personal injury or could potentially start a fire in the power plant.

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- Environmental Risks - The shifting floor could cause a major fuel or coolant leak in the plant causing significant environmental damage to the surrounding area.

Project Description

The project involves the purchase and installation of a new modular diesel generator and building. The new diesel generator is rated for 2 MW (4.16 kV) and has enough generation capacity to meet the capacity requirements of Norman Wells. The modular building is essentially a 40 foot shipping container with special enclosures designed and fabricated by the genset supplier. This type of building is significantly less expensive than a custom building that meets NTPC's specifications.

The project includes the installation of a new 4.16 kV switchgear, which will include two breakers for the diesel units and one for the Imperial Oil power generation infeed. The project will also require the installation of two feeder breakers and a station service breaker. The total project cost includes the mechanical and electrical installation and commissioning. The existing distribution system will be reused along with the existing 90,000L storage tank and the EM5 genset. The current plant site will be used to allow connection to the existing distribution line electrical connections and reuse of the existing distribution transformers and infrastructure.

Further information is provided in the project business case in Attachment A.

Grounds in Support for Project

Public Need for the Project

The existing plant has serious deficiencies that must be addressed. The current situation poses significant safety risks and environmental risks. The proposed project will correct the existing deficiencies.

Reliability of Public Utility

Under the **NTPC Act** one of the objectives of the Corporation is to ensure a continuous and reliable supply adequate for the needs and future development of the Territories. The deficiencies identified at the Norman Wells power plant need to be addressed in order to ensure the Corporation can continue to provide safe and reliable service. The proposed project has been sized to ensure it has sufficient capacity to meet the future needs of the community.

Rate Impact

The project will not have any impact on rates until it is approved by the PUB for inclusion in ratebase and rates. The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

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- Net estimated capital cost of \$4.6M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation costs to Thermal Zone only.

Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.7%.

Conclusion

The Corporation has identified a number of deficiencies at the existing Norman Wells Plant that should be addressed in order to maintain safe, reliable, cost effective service. Delaying the project puts system reliability at risk. Based on the foregoing, NTPC respectfully requests that the Board approve this application by issuing a project permit pursuant to Sections 23 and 54 of the Public Utilities Act in an amount of \$4.6 million.

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ATTACHMENT A:
BUSINESS CASE
NORMAN WELLS PLANT REPLACEMENT

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NEED FOR PROJECT

The Corporation is proposing to undertake a project to replace the power plant in Norman Wells. The current plant requires extensive repairs due to the collapsing foundation. Steel culverts were originally incorporated into the design of the building's foundation to maintain the permafrost in the ground year round. However, the culverts have rusted and the building's floor has shifted causing cracks to form in the floor, and certain areas of the structure have sunk up to 30mm. The foundation has deteriorated to a point that repairing the structure will only provide a short term solution and the building will have to be replaced. An engineering consulting firm inspected the building in 2015 and concluded that their remediation recommendations would not completely fix the problem and would only defer the need to construct a new plant.

The issues with the building's foundation pose the following serious issues and risks:

- **Safety** - The foundation under the switchgear (feeder and generator breakers) is deficient and there is a risk of electrical faults that could result in unexpected electrical arc flash hazard, which places the staff at risk of serious personal injury or could potentially start a fire in the power plant.
- **Reliability** -The instability of the foundation poses a risk to the reliability of the plant. Collapse of the foundation around the gensets would render them inoperable or potentially result in significant damage to the units.
- **Environmental Risks** - The shifting floor could cause a major fuel or coolant leak in the plant causing significant environmental damage to the surrounding area.

BACKGROUND

The current NTPC power plant in Norman Wells was first commissioned in 1961 to supply power to the town. Imperial Oil built a new power plant in the late 1990s and began to supply the power to NTPC's standby plant. This power is in turn distributed by NTPC from the standby plant to the Town of Norman Wells. Whenever the Esso plant is shut down for routine maintenance or unforced outages, NTPC's standby plant operates its generators and supplies emergency power to the town.

The plant was designed to not disturb the permafrost under the power plant foundation. Culverts were placed on top of the permafrost ground and then a gravel pad was constructed over top of the culverts. The plant's concrete slab foundation was then placed on top of the gravel pad. The design of the foundation would allow the permafrost to remain in the ground by leaving the ends of the culverts open during the winter and closing them in the summer. Over time, the culverts have severely rusted causing the floor of the plant to settle and completely collapse in certain areas. As a result of the rusting, sink holes were discovered under the concrete floor.

The Corporation places the diesel generators on genset pads, which are in turn placed on steel piles that provide firm support to the units. However, the floor around the pads is severely cracked and the floor sounds very hollow under foot traffic. The floor in the switchgear room

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has sunk by 30 mm, and the concrete floor below the wall that divides the genset bay and the switchgear bay has sunk to the degree that the wall no longer rests on the concrete floor.

ANALYSIS OF OPTIONS

Option 1: Do Nothing

The current plant in Norman Wells has serious problems with its foundation and is in need of extensive repairs. The do nothing option is not viable as it would result in the continued deterioration of the building's foundation, possibly resulting in an extended loss of power generation and exposing the Corporation and the staff to unnecessary risk. Collapse of the foundation could potentially take the current plant offline permanently and require the Corporation to ship rental units to Norman wells as a temporary measure until a new plant is put in place.

Option 2: Repair the Power Plant Foundation

Estimated Costs: \$470,000 to \$720,000

This option would consist of repairing the plant foundation as recommended by an external engineering consultant. The consultant inspected the building in September of 2015 and issued the following recommendations:

- Implement mudjacking and/or void grouting technique to lift and level the foundation.
- Add micropiles or deep piles to provide local support to the equipment.

However, none of the above remediation methods will address all problem areas. Slab removal and replacement or sub excavation and insertion of needle beams were not deemed practical due to the significant impact on plant operation or restricted access.

The consultant identified two potential concepts that could provide interim solutions for the existing plant. Concept one had an estimated cost of \$720k, while concept two was less costly with an estimated cost of \$470k.

This option is not optimal, as the ground is expected to continue to settle and any remediation undertaken will only defer the need for a new plant.

Option 3: New Modular Power Plant

Estimated Costs: \$4.6M

This option entails the purchase of a new modular diesel generator and building. The new diesel generator is rated for 2 MW (4.16 kV) and has enough generation capacity to meet the needs of Norman Wells. The modular building is essentially a 40 foot shipping container with special enclosures designed and fabricated by the genset supplier. This type of building is significantly less expensive than a custom building that meets NTPC's specifications.

The project includes the installation of a new 4.16 kV switchgear, which will include two breakers for the diesel units and one for the Imperial Oil power generation infeed. The project will also require the installation of two feeder breakers and a station service breaker. The total

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project cost includes the mechanical and electrical installation and commissioning. The existing distribution system will be reused along with the existing 90,000L storage tank and the EM5 genset. The current plant site will be used to allow connection to the existing distribution line electrical connections and reuse of the existing distribution transformers and infrastructure.

The purchase and installation of the new power plant will provide the following key benefits to the Corporation and its customers:

- Reliability – A new plant will provide a stable operating environment and remove the risk of an unexpected shift in the foundation resulting in damage to the plant and its operating assets. The overall plant reliability will be improved with the addition of a new genset and the retaining of the current EM5 genset for backup power generation, which can also be used during peak load demand if required. This will ensure that the plant is able to meet customer power demand as required.
- Environmental – The new plant will have a stable foundation that will minimize the risk of an oil or coolant leak and the resulting environmental damage and cleanup costs.
- Safety – The project will reduce the risk of electrical faults and potential arc flashes that could start a fire in the plant or injure staff.

COST ESTIMATES

Table 1 – Budget Estimates

Design

Description	2017/18
Payroll Regular	40,000
Payroll Overtime	3,000
Payroll Fringe Benefits	14,000
Consultants Lump Sum	17,000
Transportation	6,500
Accommodation	1,500
Meals	500
Contingency	25,000
Total	\$107,500

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Construction

Description	2017/18	2018/19
Payroll Regular		33,000
Payroll Overtime		26,000
Payroll Fringe Benefits		12,000
Contractors Lump Sum	526,000	-
Transportation	-	15,000
Accommodation	-	8,000
Meals	-	9,500
Freight	25,000	-
New 2MW Genset	-	1,300,000
New Switchgear	-	750,000
Temporary Site Protection	-	125,000
Gravel Foundation	-	50,000
Contingency	165,000	699,000
Total	\$716,000	\$3,027,500

Project Estimated Cost

Budget Year	Budget Estimate	IDC	Overhead	Total Cost
2017/18	\$823,500	\$27,600	\$148,000	\$999,100
2018/19	\$3,027,500	\$28,400	\$545,000	\$3,600,900
Total Project Cost				\$4,600,000

RATE IMPACTS

The project will not have any impact on rates until the time of the next General Rate Application (GRA). The rate impacts will be the largest early in the project's life since the accumulated amortization will reduce the return on rate base over time. The amortization period of the project is approximately 25 years at the currently approved amortization rates. The resulting revenue requirement increase from the project was estimated based on the following assumptions:

- Net estimated capital cost of \$4.6M
- Amortization rate of 4.04%
- Return on Ratebase of 4.87%
- Allocation of costs to Thermal Zone

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Given the above assumptions, the average rate impact of the project for NTPC's Thermal Zone customers is estimated at 0.70%. The sensitivity analysis in Table 2 shows the rate impacts of various cost scenarios.

Table 2 – Sensitivity Analysis

Project Characteristics	Base Estimate	@ 25% Higher	@ 50% Higher	@ 100% Higher
Capital Cost (\$000)	\$4,600	\$5,750	\$6,900	\$9,200
Amortization Period (Approx. Years)	25	25	25	25
GRA Approved Return on Ratebase	4.87%	4.87%	4.87%	4.87%
Revenue Requirement Impacts				
Amortization Expense (\$000)	\$186	\$232	\$279	\$372
Return on Ratebase (\$000)	\$224	\$280	\$336	\$448
Sub-Total: Revenue Requirement Increase (\$000)	\$410	\$512	\$615	\$820
Less: Estimated O&M Savings (\$000)				
Total Revenue Requirement Impact (\$000)	\$410	\$512	\$615	\$820
Thermal Zone Revenue Requirement (\$000)	\$58,418	\$58,418	\$58,418	\$58,418
Average Percentage Rate Increase	0.70%	0.88%	1.05%	1.40%

SUMMARY OF BUSINESS CASE RATIONALE

The Corporation's power plant in Norman Wells has major structural problems and needs to be replaced. The building foundation is collapsing and poses dangerous safety and environmental risks, which has the potential to negatively impact the plant's reliability and ability to generate power. It is imperative NTPC replace the plant to ensure the town has access to reliable power generation and ensure the safety of the Corporation's employees. The purchase of a new 2 MW genset will add additional generation capacity to the plant and the existing EM5 genset will be retained for backup generation thereby improving the plants ability to meet the future power demands of the community.

RECOMMENDATION

The Corporation recommends proceeding with procurement, construction and commissioning of a new power plant as outlined in option 3. This will allow NTPC to meet its obligation to provide safe, reliable power to the Town of Norman Wells in an environmentally responsible manner. The total costs to complete the project are estimated to be \$4.6M.

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Attachment A

Concordance Table Summarizing PUB Information Requirements and Business Case Information

PUB Information Requirement	Business Case Summary
A full and complete discussion of the business need that is being addressed.	<i>This topic is addressed in the Need for Project and Background sections</i>
A list of all assumptions made, including the source and basis for the assumptions.	<i>Assumptions are documented in the Cost Estimates and Rate Impacts section of the business case.</i>
An analysis of all reasonable options that could be pursued, including the do nothing option.	<i>Options considered feasible to address the business need are discussed in the Analysis of Options section.</i>
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.	<i>The Cost Estimates section addresses estimated project costs.</i>
Calculation of costs included in the business case.	<i>The Cost Estimates section addresses estimated project costs.</i>
Projected tangible benefits, along with the basis for the projected benefits.	<i>Benefits are described in the Analysis of Options section.</i>
Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome, the present value of revenue requirement, and a traditional cash flow analysis.	<i>See sensitivity analysis on page #5.</i>
A discussion of all intangible benefits.	<i>All benefits described in the Analysis of Options section.</i>
A complete discussion of risks and mitigation strategies related to the project and the recommended option.	<i>The most substantive risk related to the project are budget and schedule risks which will be managed in accordance with the Corporation's normal capital project management policies and procedures.</i>

Appendix G

Bluefish Post Project Report

Post Project Review

Bluefish Dam Replacement

Project Summary

The original Bluefish Hydro Facility was located on the Yellowknife River between Bluefish Lake and Prosperous Lake, and was owned and operated by the Northwest Territories Power Corporation. The facility provided approximately 20% of Yellowknife's electrical needs. The dam at the outflow of Bluefish Lake created a reservoir for the turbines to operate throughout the year. This dam was 70 years old and kept serviceable by upgrades carried out in 1972, 1983 and 2007. However, it reached the end of its service life and the risks to its continued use became unacceptable.

Bluefish Dam was in an advanced state of deterioration due primarily to the age of the facility. This was evidenced by the following:

- Increased seepage through the dam due to breakdown of the upstream impermeable barrier installed in 1983. This breakdown appears to be caused by a collapse of the timber crib structure; this is evidenced by settlement in the upstream mat, consistent with the upstream face of the timber crib. This settlement coincided with the formation of the sinkholes.
- Advanced deterioration and collapse of the overflow spillway. Deterioration of the spillway was suspected and was outlined in previous studies. This was confirmed in 2008 with the delamination of the timber sheeting on the dam. The exposed timber crib structure was completely deteriorated and collapsing. This present state of deterioration presents significant risk.

These risks influence the following:

- NTPC's ability to guarantee long-term protection of the environment of the Yellowknife River and Prosperous Lake downstream of the dam.
- NTPC's ability to guarantee the safety of recreational fishers using the area adjacent to the generation.
- NTPC's ability to meet internal Green House Gas targets.
- NTPC's ability to reliably provide cost effective power to the North Slave area.

The loss of this infrastructure would reduce the Corporation's hydroelectric generation and require additional diesel generation from the the Jackfish diesel generating station. This would require 11 million litres of diesel fuel per year for equivalent capacity. This would not include any additional generation equipment that could be required to meet required excess capacity guidelines. After considering the various alternatives, the Corporation decided that the best option for long-term reliability and consumer electrical rates is to build a new dam, downstream of the existing dam. The replacement dam was built approximately 400 metres downstream from the current site.

Project Deliverables

The objectives of this project were as follows:

- Provide a facility that can operate with minimal risk to the environment.
- Provide a facility that meets project objectives while ensuring the lowest cost value to the ratepayer.
- Provide a facility that meets the current standard engineering principals and current dam safety guidelines as published by the Canadian Dam Association
- Provide a facility that provides safe operator control and water management.
- Provide a facility that meets the requirements of the regulatory agencies (Department of Fisheries and Oceans (DFO), Environment Canada, Indian and Northern Affairs Canada (INAC) and the Mackenzie Valley land and Water Board.)
- Provide a facility that assures on-going reliable cost effective power will be provided to the Yellowknife service area.

Replacing the existing dam to ensure the renewable capacity of the Snare-Yellowknife system was maintained, while also maintaining the environmental integrity of the site and waterway determined project deliverables. The new construction also required a re-routing of the access road. Meeting environmental and regulatory requirements required the creation of a bottom outlet structure to allow for fish movement downstream.

The original proposed project did not include the construction of a spillway; this was added and included in the updated project permit application that was approved in 2011. All project deliverables were completed with modifications necessary to the bottom outlet structure as detailed in Table 1. The project was completed in 3 phases: Engineering / Design, Construction and simultaneously Site Services / Project Support.

Table 1
Comparison of Planned and Completed Works at Bluefish Generation Station

Planned Deliverable	Actual Deliverable	Comments
Access road to link Bluefish site to dam crest	New road completed.	As planned
Replacement Dam per defined objectives	Rock fill dam with stainless steel core completed.	As planned, all regulatory requirements and standards met
Bottom Outlet Structure	Completed including IFR gate and bottom outlet gate for flow regulation.	Reduced cladding / weather proofing as decided unnecessary. Additional plunge pool required to ensure fish survival.
Overflow Spillway including bottom outlet.	Spillway completed to specified size.	As planned with update project scope / budget

Project Costs

The PUB has approved the project at \$37.4 million under a revised Major Project Permit. The project cost increased by \$18.9M to \$37.4M. Due to poor rock conditions for blasting, and additional natural features, grouting costs were much higher than expected. Critical to the long-term stability of the new dam, and despite some success at renegotiating rates with vendors, unanticipated grouting was a substantial portion of the contingency used. Schedule delays due to vendor issues in 2011 extended the timeline in 2012 and this accounted for most of the remainder of the budgeted contingency use.

Table 2 summarizes by project phase the budget vs actual costs. Costs include decommissioning in 2012. Final project costs were under the final approved budget by ~.067M.

Table 2
Actual vs. Budgeted Costs (based on final PUB approved budget)

Project Phase	Budgeted Cost	Actual Cost	Comments
Design & Engineering	2,936	1,846	Completed quickly and with less detail due to emergency nature of project.
Construction	25,239	29,020	Incl. contingency, delays in 2011 & grouting major portions
Site Services / Project Support	2,854	4,053	Incl. contingency, testing, truck, office expenses
Contingency	2,891		
Overhead	1,046	532	
IDC	2,434	1882	
Total	37,400	37,333	

Project Schedule

Under the final approved project plan and scope, the targeted commissioning of spring 2013 was achieved. Delays in 2011 extended the construction and decommissioning in 2012, but did not delay the project end date.

|

Table 3 – Project Schedule

Project Phase	Scheduled Completion	Actual Completion	Comments (explain variance)
2009-10 – Engineering and Design	Prior to construction Feb. 2011	Jan. 2011	No delays.
2011 – Site prep, blasting, aggregate production, initiate dam construction	Feb. 2 – Oct. 19th	Oct. 31	Not complete, work to carry over.
2012 – spillway construct, complete dam, access road, decom old dam	Mar. 1 – Aug. 19	Nov. 14	Carryover from work incomplete in 2011, extended year and costs.
2013 - commission	April	April	As scheduled.

Transition to Operations including anticipated value to org. & customers

The project transitioned to operations with minimal issues. The unit has generated at the anticipated levels without significant corrective repairs being required. Some minor seepage was noted, but that was determined not to be significant enough to affect long-term stability of the site and has not been actioned as a result.

A detailed Operations and Maintenance manual is being developed to assist with long-term maintenance of the site, and to have a better understanding of the various monitoring instrumentation and tools installed. Formalizing this material is currently underway and should be completed in this fiscal year.

Because of the successful transfer to operations, the anticipated project benefits and returns to ratepayers have not changed since the time of application and the project is anticipated to provide ratepayers with reliable renewable energy and rapid payback on investment.

Recommendations and Lessons Learned

Key lessons from the project focus on contract negotiations, both successful and unsuccessful.

Recommendation 1

Alliance type contract with North American Construction Ltd. was an opportunity to reduce costs by allowing a sharing of responsibilities and risks on a “best for project” basis. The original price was based on good faith estimates of project costs, and as items emerged that

would potentially use contingency funds there was considerable dispute with the contractor as to what constituted increased costs (contingency) and what was in fact a change in scope. In order for this type of contract to be successful the design and engineering, and the subsequent budget estimates must be as accurate as possible. The emergency nature of this project was not conducive to NTPC achieving the desired benefit from this type of contract. Design changes, and significant project updates make it difficult to determine what changes be reflected in the contractor share of contingency. It is more about getting a better baseline and reducing unknowns so end cost will be more in line with good faith estimate. The estimate was based on a nearly complete design and therefore the differences between the assumptions made by the contractor on the partially complete design and the final design provided for considerable scope changes and cost increases.

Recommendation 2

The principal construction contractor was given full site control, including responsibility for site safety, security and management of sub-contractors. There is considerable difficulty in managing safety on a contractor-managed project, and contract design ultimately assigned control to the vendor who is in the best position to ensure safety of their employees and not expose NTPC to that risk.

Recommendation 3

A considerable portion of the budget contingency was used to cover increase costs incurred during grouting of natural features to prevent leaks and seepage. The contract design was based on an assumption of the amount of grout to be used, and a per unit price agreed. The contractor would have built into his per unit price the cost to cover all of his fixed expenses (considerable portion in a remote project). When the quantity of grout required become much greater than originally estimated the inflated per unit price became a major cost driver. The vendor was reasonable in renegotiating his per unit costs in the second year and negotiating a staged per unit cost (decreasing as quantities pass thresholds), but the contract design in this instance was nonetheless responsible for significant unanticipated costs.

Appendix H
Terms and Conditions of Service

DRAFT TERMS & CONDITIONS OF SERVICE



TERMS & CONDITIONS OF SERVICE

Effective Date: XXXXXXXX

DRAFT TERMS & CONDITIONS OF SERVICE
NORTHWEST TERRITORIES POWER CORPORATION
TERMS AND CONDITIONS OF SERVICE
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LIST OF SCHEDULES

SCHEDULE "A" MAXIMUM CORPORATION INVESTMENT

SCHEDULE "B" CONDITIONS OF UNDERGROUND SERVICE

SCHEDULE "C" FEES AND SERVICE CHARGE SUMMARY

DRAFT TERMS & CONDITIONS OF SERVICE**TERMS AND CONDITIONS OF SERVICE****1.0 Introduction****1.1 Approval**

In accordance with the *Northwest Territories Power Corporation Act* R.S.N.W.T. 1988, c. N-2 and the *Public Utilities Act* N.S.N.W.T 1988, c.24, these Terms and Conditions of Service (hereinafter referred to as "Terms") have been approved by the Public Utilities Board of the Northwest Territories (hereinafter referred to as the "Board"), and may not be changed without the approval of the Board.

1.2 Effective Date

These Terms come into force 60 days following the date of the Board's order and replaces all previous versions of the Corporation's Terms. Whenever the Board approves an amendment, revisions will be issued, with the effective date of the amendments indicated on the top of each affected page.

1.3 Conflicts:

If there is any conflict between a provision expressly set out in an Order of the Board and the Terms, the Order of the Board shall govern.

1.4 Headings:

The division of the Terms into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of the Terms.

1.5 Extended Meanings:

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

1.6 Statutes:

Unless otherwise specifically indicated, all references to statutes include

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amendments thereto, as well as all regulations, standards and guidelines established pursuant to that statute.

1.7 Schedules:

The following schedules are attached to and form part of the Terms:

Schedule "A" – Maximum Corporation Investment

Schedule "B" – Conditions of Underground Service

Schedule "C" – Fees and Service Charge Summary

2.0 Definitions

The following words or phrases, when used in these Terms and Conditions of Service, or Customers' Application(s) for Service shall, unless the context otherwise requires, have the following meanings:

2.1 Applicant:

Means any person which requests Service from the Corporation.

2.2 Billing Adjustment:

Means the correction of a prior over or under-billing.

2.3 Billing Demand

Means the Demand upon which billing to a Customer is based and may be estimated or measured by an approved Demand Meter. Unless otherwise specified in the Demand for the current billing period or the maximum Demand experienced during the 12-month period ending with the current billing period for determination of Demand Charges, the Billing Demand shall not be less than 5 kW per month. All references in the Rate Schedules to a measurement in "kW" at a particular rate shall be deemed to include a reference to "kVA" measured at the same rate and vice versa.

2.4 Connected Load:

Means the sum of the capacities or ratings of the electric energy consuming apparatus connected to a supplying system.

2.5 Construction Contribution:

The difference between the capital cost incurred by the Corporation by installing

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the Corporation's Facilities to serve a Customer and the Maximum Corporation Investment specified in Schedule "A".

2.6 Corporation:

Means the Northwest Territories Power Corporation and any of its employees, agents, or contractors.

2.7 Corporation Facilities:

Means physical plant owned or leased by the Corporation including, without limitation, electrical energy production plant, transmission and distribution systems, transformers, meters, equipment and machinery used in the production transmission and distribution of Energy.

2.8 Customer:

Means any person to whom Service is being or has been provided, whether or not:

- a) the person did not request Service from the Corporation; or
 - b) the name or signature of the person appears on a written application for Service or contract of Service
- and includes an Applicant to which the Corporation has decided to commence providing Service.

2.9 Customer Charge/Service Charge:

Means that portion of the charge for Service, excluding any Facilities Charge, which does not vary with the level of Demand or Energy consumption. This charge is assessed to partially offset the various fixed costs associated with the provision of Service such as service lines, meter reading and billing of accounts.

2.10 Customer Facilities:

Means the equipment to be supplied by the Customer to allow for the attachment of Corporation Facilities for the delivery of Energy to the Customer, installed in accordance with applicable statutes, regulations, standards and codes.

DRAFT TERMS & CONDITIONS OF SERVICE**2.11 Customer Service Order (CSO):**

Means an agreement for the provision of a Service pursuant to these Terms and Conditions of Service, between the Corporation and the Customer.

2.12 Demand:

Means the rate at which, electric Energy is delivered from the Corporation Facilities to a Customer expressed in kilowatts (kW), kilovoltamperes (kVA) or other suitable unit, at a given instant or averaged over any designated period of time.

2.13 Demand Charge:

Means that portion of the charge for Service based upon the electric Demand (measured in units of kW or kVA) consumed and billed on the basis of Billing Demand at the applicable rate.

2.14 Electricity:

Means electric power, and includes both Energy and Demand.

2.15 Energy:

Means, as the context requires:

- a) electric energy expressed in kilowatt-hours (kWh); and
- b) thermal (heat) energy which is supplied to or through a heating system by hot water, hot air, steam or glycol expressed in kilowatt-hours (kWh_T) or gigajoules (GJ).

2.16 Energy Charge:

Means that portion of the charge for Service based upon the Energy consumed or billed.

2.17 Facilities Charge:

Means all sums not collected through Demand Charges, Energy Charges, and Customer Charges charged to a Customer's account to recover:

- a) the costs associated with the dedication of Corporation Facilities to that

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Customer;

- b) all other charges arranged by agreement with the Customer, other than Energy Charges, Demand Charges and Customer Charges.

2.18 General Service:

Means a classification of Service referring to other than Residential, Industrial, Wholesale, Municipal Street Lighting and Private Area Lighting Service. This classification also includes, without limitation:

- ~~a) service provided to a Government Customer;~~
- b) a single family dwelling where a business is carried on within the dwelling and the entire dwelling is supplied through one meter
- c) a common use area associated with a group of residential dwellings (for example, utility rooms), and
- d) a multiple unit dwelling supplied through one meter.

2.19 Gigajoule (GJ):

Means the standard unit of energy in the SI or metric system of measurement.

2.20 Government Customer:

Means a Customer whose account for Service is payable or funded by a federal, territorial or municipal authority, or whose function is to provide on behalf of or to the public:

- a) executive, legislative and other general government support services; or
- b) justice, public order, postal, or safety services; or
- c) administration of: human resource programs; environmental quality or compliance programs; housing programs; health care programs; social assistance programs; urban planning services; community development programs; economic programs; or educational programs; or
- d) space research and technology services; or
- e) territorial or national security or international affairs services, but does not include a User Pay Customer.

DRAFT TERMS & CONDITIONS OF SERVICE**2.21 Government Industrial:**

Means a classification referring to a ~~Government~~ business, the primary business of which is resource exploration, development or mining, and includes, but is not limited to, the construction, operation, reclamation or shut down phases of such business.

2.22 Intermittent Renewable Generation

Customer owned generation that produces power from solar or wind or other forms of energy that may be approved by the Corporation, based on the generation deriving from resources that are continually replenished and tending to operate at a low load factor.

2.23 Interruptible Service:

Means Electric Service provided by the Corporation to a Customer under agreements, which permit curtailment or cessation of delivery by the Corporation.

2.24 Joint Use Service:

Means the provision by the Corporation of leased space on existing Corporation transmission and distribution poles, where sufficient space is available, to electrical and communication utilities in areas in which the Corporation provides Service.

2.25 Load Factor:

Means the ratio of the average demand (in kW) supplied during a designated period to the peak or maximum load (in kW) occurring in the period. When expressed as a percentage, Load Factor during a period is the ratio of total energy consumed during the period (in kWh) to the maximum load (in kWh) during the period.

2.26 Maximum Corporation Investment:

Means the available Corporation investment in dollars as set out in Schedule "A".

2.27 Multiple Unit Dwelling:

Means a residential building containing more than one residential dwelling unit.

DRAFT TERMS & CONDITIONS OF SERVICE**2.28 Municipal Corporation:**

Means a corporation established or continued as a city, town, village, hamlet or charter community by or under the *Cities, Towns and Villages Act*, R.S.N.W.T. 1988, c. C-8, *Charter Communities Act*, R.S.N.W.T. 1988, c. C-4 or *Hamlets Act*, R.S.N.W.T. 1988, c. H-1.

2.29 Municipal Street Lighting Service:

Means a classification referring to the supply of Electricity to municipal street lighting by the Corporation in communities serviced by the Corporation and includes, without limitation, the installation, operation and maintenance of standard street lighting luminaires ~~on wood poles and serviced by overhead wiring.~~

2.30 Point of Delivery:

Means, unless otherwise specified in an accepted application for Service or an agreement or contract, the point at which the Facilities required to provide Service are connected to Customer Facilities

2.31 Primary Service:

Means service of Electricity provided by the Corporation at primary voltage levels to an end-use Customer, with all secondary transformation and distribution provided by the Customer.

2.32 Private Area Lighting Service:

Means Service involving the supply of Electricity to off-street and area lighting by the Corporation in communities serviced by the Corporation and may include the purchase, installation and energizing of the area lighting.

2.33 Rate Schedules:

Means the schedules of regulated rates prepared by the Corporation pursuant to the *Public Utilities Act*, as amended from time to time.

DRAFT TERMS & CONDITIONS OF SERVICE**2.34 Residential Service:**

Means Service to a detached single family dwelling or an individual unit in a multiple unit dwelling where Service is provided to the unit through a single meter, which does not serve another unit in the multiple unit dwelling. To be classified as Residential the detached single family dwelling or individual unit in a Multiple Unit Dwelling must be used exclusively as a residence and must not be used for Industrial, Wholesale, or General Service purposes.

2.35 Seasonal Service:

Means Service that in the sole opinion of the Corporation acting reasonably is anticipated to be repeatedly connected and disconnected at the Customer's request on a seasonal basis.

2.36 Service:

Means the delivery of Energy or the making available of Energy for delivery at the Point of Delivery.

2.37 Short Term Temporary Service:

Means Service that in the sole opinion of the Corporation acting reasonably will be required for a period of 12 months or less, and subsequently will not be required again for a period of at least 12 months.

2.38 Temporary Construction Service:

Means Service provided during the construction or renovation of a building by way of a meter situated in a temporary location.

2.39 TMI:

Means a Time and Materials Invoice used to bill for costs incurred for work undertaken by the Corporation in relation to a maintenance agreement or other arrangement between a Customer and the Corporation.

2.40 User Pay Customer:

Means a Residential Service Customer occupying, as a tenant, a dwelling owned

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or leased by the Northwest Territories Housing Corporation.

2.41 Wholesale:

Means a Customer that is a business whose primary purpose is to distribute and re-sell electricity purchased from the Corporation.

3.0 Agreement**3.1 Application:**

These Terms apply to the Corporation and to every Applicant and Customer.

3.2 Contract:

Notwithstanding the provisions of Section 3.1, and subject to approval by the Board, the Corporation may enter into a contract with a Customer specifying the terms and conditions of Service, which may vary from and supersede these Terms.

3.3 Resale:

Without the prior written consent of the Corporation, a Customer may not sell, exchange or otherwise dispose of Energy provided by the Corporation.

3.4 Ownership:

The Corporation retains ownership of all facilities used to provide Service to a Customer, whether or not facilities are located on lands owned by the Corporation, and whether or not the capital cost of such facilities were in whole or in part paid by the Customer.

Unless a contract between the Corporation and the Customer specifically provides otherwise, payment made by a Customer for costs incurred by the Corporation in installing facilities does not entitle the Customer to ownership of any such facilities.

3.5 Customer Generation:

A Customer must sign an agreement with the Corporation if the Customer wishes

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to use Service:

- a) in parallel operation with; or
- b) as supplementary, auxiliary or stand-by Service to any other source of Energy.

The Corporation will provide retail stand-by service to back-up customer self-generation where surplus capacity is available. Rates for such service shall be established by the Board provided however that self-generation customers utilizing intermittent renewable generation are exempt from payment of the standby service charge.

3.6 Net Metering Service:

Non-Government Customers ~~in all the rate zones~~ and Municipal Government Customers ~~in Thermal zone~~ who install Intermittent Renewable Generation may be eligible for the Net Metering Program provided the Corporation is satisfied that metering, billing and other requirements of the program can be met.

Inflows of electricity from the Corporation's system to the Customer, and outflows of electricity from the Customer's generating facility to the Corporation's system, will be determined by means of a single meter capable of measuring flows of electricity in both directions. Alternatively, the Corporation may be required that separate meters be installed to measure inflows and outflows of electricity.

Meter reading and billing frequency will be in accordance with the Corporation's Rate Schedules as reviewed and approved by the NWT Public Utilities Board from time to time. Net metering customers will pay the applicable demand and customer charge each month. For energy billing, at the end of each billing period the Corporation will determine the "Monthly Net Energy" applicable for that billing period, defined as the difference between the electricity supplied by the Corporation to the Customer during the billing period and the electricity delivered from the Generating Facility to the Corporation's system during the billing period. In any month, if Monthly Net Energy is zero or negative (i.e., the customer in total

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delivered more electricity to the Corporation's system than the customer consumed supplied by the Corporation), the Corporation will credit the Monthly Net Energy amount to the customer's account (the "banked balance") and the customer will not be charged any Energy Charge for the month.

If in any month the Monthly Net Energy is positive (i.e., the customer in total consumed more energy supplied by the Corporation than the customer delivered to the Corporation's system), then the Corporation will apply energy units from the banked balance (if any) as credits against the monthly Net Energy amount. In the event the banked balance exceeds the monthly Net Energy, the Net Energy will be fully offset by banked balance and the customer will not be charged any Energy Charge for the month. If the Monthly Net Energy exceeds the banked balance, then the full banked balance will be applied as credits against the Monthly Net Energy and only the residual Monthly Net Energy which was not offset by banked balance credits will be billed to the Customer in that month at the applicable retail rate.

Any banked balances that exist at year-end (March 31) will be reset to a zero balance.

3.7 Frequency and Voltage Levels:

The Corporation will make all reasonable efforts to supply Electricity at 60-Hertz alternating current. The voltage levels and variations will comply with those specified as "standard" by the Canadian Standards Association. Not all standard voltages may be available at a particular location.

4.0 Application for Service

4.1 General:

To enable the Corporation to provide the requested Service, an Applicant may be required by the Corporation to supply information either verbally or in writing respecting their Connected Load, preferred supply conditions, lot number or street address, location of building on lot, and any other pertinent information requested by the Corporation, such as credit history or references. An Applicant shall be required to sign a Customer Service Order (CSO) or enter into a written

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contract for Service.

For a new electric Service location, the Customer must ensure that the Corporation has received each applicable permit and connection authorization directly from the applicable Electrical Safety Division of the Government of the Northwest Territories.

Before connecting any Service, the Corporation will inform the Applicant if there are any special conditions that must be satisfied and the satisfaction of any such conditions shall be a precondition to the Corporation commencing Service.

Notwithstanding anything in section 4.1, whether or not a Customer has signed a Customer Service Order or contract for Service, these Terms and Conditions and the rates applicable to the Service supplied by the Corporation will apply to any Customer receiving Service from the Corporation.

4.2 TMI Deposit:

Where an Applicant or Customer are required by these Terms and Conditions to pay a TMI Deposit, the TMI Deposit will be determined in accordance with the Miscellaneous Fees/Charges set out in Schedule "C".

4.3 Service Connection:

Where the Corporation does not have linemen based in a community, a Service connection in the Community will be completed during the Corporation's next scheduled maintenance work in the community following the date that the Corporation agrees to provide the Service connection.

If the Customer requests that Service commence earlier than the Corporation's next scheduled maintenance work in the Community, the Customer will be required to sign a TMI for the cost, as estimated by the Corporation, of connecting the Service at an earlier date, and must provide a TMI Deposit prior to the date any work respecting the Service connection is commenced by the Corporation. After the work is completed, the Corporation will make any

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adjustments necessary to the TMI to reflect the Corporation's actual cost of performing the work. The Customer will pay any additional amounts owing under the TMI, or the Corporation will refund any excess amounts paid by the Customer, as applicable. The Corporation will not commence providing Service until all amounts owing to the Corporation under the TMI are paid in full.

4.4 Short-Term Temporary Service:

Where an Applicant requests Short-Term Temporary Service, or the Corporation in its sole discretion acting reasonably, believes that Service requested by an Applicant will be Short-Term Temporary Service, the Applicant shall, prior to the Corporation commencing any work on the Service connection, pay the Corporation's total cost as estimated by the Corporation of installation and removal of the required Corporation Facilities, plus the cost of unsalvageable material as follows:

- a) At the time the Applicant submits request for Service, the Applicant must sign a TMI and provide a TMI deposit.
- b) Following the termination of Service the Customer shall be reimbursed or invoiced for the difference between the TMI deposit paid and the aggregate of the actual cost of construction, plus the cost of unsalvageable material, plus the removal costs as estimated by the Corporation.
- c) Following the removal of the Corporation Facilities required to provide Service to the Customer, the Customer will be reimbursed or invoiced for the difference between the estimated costs and the actual Corporation Facilities removal costs.

4.5 Rejection of Application for Service:

The Corporation may, in its sole discretion acting reasonably, reject any Applicant for Service when:

- a) the type or quantity of Service requested is not available or normally provided by the Corporation in the locality where Service is requested;

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- b) the Applicant or Customer does not have currently in force all permits or other authorization that may be required for the connection;
- c) the Corporation determines at its sole discretion acting reasonably that the Applicant is not credit-worthy, or a previous or other account held by the Applicant with the Corporation is in arrears;
- d) the Applicant fails to provide a security deposit or letter of credit from a suitable institution in a form and substance acceptable to the Corporation;
- e) the Corporation requires a separate contract due to the unique nature of service conditions;
- f) any representation made by any Applicant to the Corporation for the purpose of obtaining Service is, in the Corporation's opinion acting reasonably, fraudulent or misleading;
- g) the Applicant has not, after being requested by the Corporation to do so, provided a signed written Customer Service Order or contract for service, or has refused to sign these documents;
- h) the Applicant is not the owner, the owner's representative or an authorized occupant of the premises; or
- i) the service requested is already supplied to the premise to another customer who does not consent to having their service discontinued.

5.0 Charges for Service**5.1 Connection Fee:**

Whenever a Service connection is made, the Customer shall pay a non-refundable connection fee as set out in Schedule "C".

If the Corporation agrees to make a connection other than during the Corporation's normal schedule for such work, the Corporation may charge by way of a TMI in addition to the amount set out in Schedule "C" its cost to make the connection, but in no event may the Corporation charge in excess of the Corporation's actual cost to make the connection.

The connection fee will be included in the Customer's first billing.

DRAFT TERMS & CONDITIONS OF SERVICE**5.2 Reconnection:**

When the Corporation receives an Application for the relocation of Service or is requested to reconnect or restore Service to a Customer whose Service was previously discontinued by the Customer, terminated by the Corporation or restricted by a current-limiting device, the Customer shall pay:

- a) all amounts owing to the Corporation, which shall include, if reconnection occurs within 12 months and billed at rates where Demand Charges apply, the Demand Charge in effect immediately prior to disconnection for each month of the interval between disconnection and reconnection;
- b) a reconnection charge as per Schedule "C" ~~attached hereto if the reconnection is made during the Corporation's normal schedule for such work, or in any other case, an amount not exceeding the Corporation's actual cost of reconnection;~~ and
- c) the security deposit required under Sections 5.7 and 5.8.

Where a metered service has been disconnected for a continuous period of 90 days or more, the Corporation in its sole discretion acting reasonably may require an electrical inspection of the Customer Facilities at the Customer's sole expense.

5.3 Application of Rate Schedules:

The Customer shall pay the charges for Service as set forth and contained in the applicable Rate Schedules in effect from time to time.

Where a Customer is receiving service for both Residential and General Services, the General Service rate applicable in the Service area will be charged in respect of all Energy provided to the Customer at the Customer's Point of Delivery. Provided, however, that if the customer installs, to the Corporation's satisfaction, separate meters to record the amount of Energy used for each of Residential and General Services, then the Corporation's applicable General Service rate will apply to the energy consumed under General Service and the Corporation's applicable Residential Service Rate will apply to the Energy

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consumed under Residential Service.

Residential Service rates applicable in the Service area will apply to Temporary Construction Service where a Customer is building his/her own single family residence.

General Service rates applicable in the Service area will be applied to Temporary Construction Service provided to a contractor/developer for the building of homes other than the contractor's/developer's private residence. General Service rates applicable in the Service area will be applied to Temporary Construction Service respecting non-residential construction projects.

5.4 Power Amplifier Boxes:

Service provided for power amplifier boxes shall be billed at the General Service rate applicable in the service area assuming continuous use of the power amplifier box at its maximum rated consumption. At the Customer's request, and after the Customer has installed a CSA approved meter receptacle, the Corporation will install a meter. Power Amplifier Boxes affixed to Corporation's Facilities are a Joint Use Service and shall be charged for in accordance with Section 8.0. Service provided in respect of the power amplifier box will be billed based on actual consumption recorded by the meter.

5.5 Power Bill Copying Charge:

The Customer will be subject to a fee for being provided an additional copy of a power bill, including any related documentation. The charge for providing this service is set out in Schedule "C".

5.6 Change in Service Requirements:

Where the purpose for which a Customer uses all or a portion of the Service provided by the Corporation changes from one classification to another, the Customer will immediately notify the Corporation of the change. When the Corporation is so notified, or when the Corporation believes on reasonable grounds that the purpose has changed, the Corporation will calculate the

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Customer's bill on the basis of the rate which the Corporation, acting reasonably in the circumstances, determines to be applicable to the Service commencing in the next billing period.

5.7 Security Deposit:

The Corporation shall require a security deposit as a pre-condition to Service or an increase to an existing security deposit where:

- a) credit worthiness has not been established by an Applicant for Service to the satisfaction of the Corporation;
- b) accounts are in arrears for previous Service to the Applicant by the Corporation;
- c) Service is to be reconnected which has been discontinued for reasons of non-payment of accounts;
- d) the Service to be provided will be Short-Term Temporary Service; or
- e) the Customer is the subject of bankruptcy, insolvency or a similar proceeding, enters into receivership, or ceases to be a corporate entity.

5.8 Amount of Security Deposit:

A security deposit, when payable, shall be in a form and substance acceptable to the Corporation in the following amounts:

a) Residential Service:

For Customers with less than one year of previous billing history with the Corporation, an amount as set out in Schedule "C".

As an alternative to a security deposit, the Corporation may, at its sole discretion acting reasonably, accept from an Applicant for Residential Service proof of a good credit history from a utility service within the last 12 months ~~or a letter attesting to the Customer's good credit history from a chartered bank.~~

b) User Pay Customer:

For User Pay Customers, an amount set out in Schedule "C".

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- c) General, Short-Term Temporary, Industrial and Wholesale Customers Service:

For a Customer at a location or Point of Delivery with less than one year of previous billing history with the Corporation, an amount, as estimated by the Corporation, equal to the sum of the billings for the two months during which the Corporation forecasts the highest consumption of Energy at the Customer's Service location during the next 12 month period.

For a Customer at a location with at least one year of previous billing history with the Corporation, an amount, as calculated by the Corporation, equal to the sum of the billings for the two months having the highest Energy consumption during the most recent 12 month period.

As an alternative to a security deposit, the Corporation, at its sole discretion acting reasonably, may accept from an Applicant an irrevocable letter of credit from a Canadian chartered bank.

The Corporation has the right to immediately issue a 48 hour notice of disconnection to a Customer if the Customer's ~~cheque~~ payment of a security deposit is not honored by the Customer's financial institution.

5.9 Interest and Refund of Deposits:

The Corporation will pay simple interest on the security deposit from the date the deposit is paid, at an annual rate of interest equal to the daily interest savings rate in effect ~~at the end of each month~~ quarterly as posted by the Bank of Nova Scotia. Such interest will be credited monthly to the Customer's security deposit account for each full month that the security deposit is held by the Corporation.

A Customer's security deposit will be refunded after 1 year of good credit history with the Corporation, or when the Customer is disconnected from Service other than for default in payment of accounts. Security deposits will be returned to the Customer by way of credit to the Customer's account.

DRAFT TERMS & CONDITIONS OF SERVICE**5.10 Use of Security Deposits**

If a Customer fails to pay an amount billed, and collection action has been initiated by the Corporation, the Corporation may apply all or any portion of a Customer's security deposit toward payment of the amount(s) in arrears, including interest.

When the Corporation has taken this step, the Customer may be required to pay a security deposit as required under Sections 5.7 and 5.8, or to pay to the Corporation the amount deducted from the Customer's security deposit.

Upon termination of Service, the Corporation may apply all or any portion of a Customer's Security Deposit, including interest, toward payment of any amount due and owing by that Customer.

5.11 Unclaimed Security Deposits:

If the Corporation is unable to locate the Customer to whom a security deposit is payable and the security deposit remains unclaimed for six (6) years from the date the Customer was disconnected from Service, then the deposit becomes the property of the Corporation immediately after the six (6) year period has expired.

6.0 Municipal Street Lighting Service**6.1 Street Lighting Service Conditions:**

The Corporation shall be responsible for the provision of Energy to the street light luminaires. The Corporation shall also be responsible for normal maintenance of the luminaires, photo electric cell replacement and lens cleaning and replacement. The Corporation shall not be responsible for excessive damage due to vandalism. (see Section 6.3 below)

6.2 Maintenance Adjustment:

Upon being notified in writing of an outage of a luminaire:

- a) Where the Corporation has linemen based in the community in which the outage occurred, the Corporation will use reasonable efforts to carry out

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maintenance to restore Service within one week of having received such notice. Should the Corporation be unable to carry out the maintenance required to restore the luminair within one week of having received written notice, a credit towards the monthly rental applicable to the luminair shall be given by the Corporation to the Customer based on the length of the outage.

- b) Where the Corporation does not have linemen based in the community maintenance will be carried out during the next regularly scheduled maintenance trip to the community following the Corporation's receipt of such notice. If the Corporation has been unable to carry out the maintenance required to restore the luminair within three (3) months after being notified of the outage, a credit towards the monthly rental applicable to the luminair shall be given by the Corporation to the Customer based upon the length of the outage.
- c) If a Customer requests that the Corporation carry out maintenance work prior to the Corporation's next regularly scheduled maintenance trip, the Customer will be billed for the Corporation's costs of performing such maintenance by way of a TMI, and a TMI deposit must be paid by the Customer before maintenance work will commence. After the maintenance work is complete, the Customer will be invoiced or refunded the difference between the Corporation's actual cost to complete the maintenance work and the TMI deposit.

6.3 Vandalism:

The Corporation will absorb the maintenance costs associated with the repair of vandalized luminaires to a maximum annually in each community of one luminair or 1% of the total number of luminaires in the community, whichever is greater.

Repetitive breakage or extreme breakage at one time shall not be absorbed by the Corporation. Vandalism of this type shall be reported to the Local Authority, outlining the extent of the damage and the estimated cost of repair. Providing the

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Local Authority agrees in writing to absorb these costs, the Corporation shall effect repairs and restore Service. Otherwise, the street light luminair(s) shall be removed and billing shall be immediately discontinued.

6.4 Application for Street Lighting Service:

Municipal Corporations requesting municipal Street Lighting Service shall do so in writing to the ~~appropriate~~ Corporation. The request shall specify the number, type and size (Watts) of luminaires required, and be accompanied by a suitable plan indicating the location where each luminaire is to be installed. The Corporation shall not bear any responsibility in regard to the adequacy of lighting resulting from the number, type and size of luminaires requested.

The Corporation shall review the Municipal Corporation's request and advise the Municipal Corporation in writing of present charges for the Street Lighting Service requested and if any additional charges shall be applied due to unusual installation circumstances (see Section 6.6).

6.5 Installation:

Upon receiving written approval from the appropriate authority to proceed, the Corporation shall purchase, install and energize the street light luminaires at a time during the normal course of its maintenance schedules. Billing shall commence immediately after the installation is completed.

6.6 Non-Standard Service:

Charges for Street Lighting Service are based upon the installation of luminaires on existing wood poles provided for distribution of overhead Service in the community. Should additional wood poles, transformers, secondaries or other facilities be required, the cost of providing and installing the additional facilities is the responsibility of the Customer.

Should non-wood poles and/or underground wiring be required, this may be done by the Corporation at the cost of the Customer.

DRAFT TERMS & CONDITIONS OF SERVICE**7.0 Private Area Lighting Service****7.1 Application for Service:**

Customers requesting Private Area Lighting Service shall do so in writing to ~~an appropriate office of~~ the Corporation. The request shall specify the number, type and size (Watts) of luminaires required and be accompanied by a suitable plan indicating the location where each luminaire is to be installed and identifying the Customer's power source for each fixture. The Customer is responsible for ensuring that the Corporation has received all applicable permits and connection authorization directly from the applicable Electrical/Mechanical Safety Division of the Government of the Northwest Territories.

7.2 Installation:

The Corporation shall review the Customer's request and advise in writing, in a timely manner, the estimated cost of providing this installation.

Upon receiving payment for the estimated cost of the installation, in advance, from the Customer, the Corporation shall purchase, install and energize the area lighting. Any difference between the estimated cost and the actual cost incurred by the Corporation shall be either invoiced or refunded to the Customer.

Power supply for Private Area Lighting Service may be from the Customer's metered distribution panel, or at the option of the Corporation, from a separate power supply.

7.3 Rates Classification:

Where separate metering is in place for Private Area Lighting Service, the rate classification shall be that associated with the classification of Service being provided to the Customer.

Where the Private Area Lighting Service is not metered, the Corporation will charge monthly fixed rates as determined in accordance with its Rates Schedules.

DRAFT TERMS & CONDITIONS OF SERVICE**7.4 Ownership:**

The Corporation shall not purchase, lease, or otherwise become the owner of Private Area Lighting Facilities. Subject to Section 7.5 the Customer shall be responsible for all maintenance of the Facilities.

7.5 Maintenance:

The Corporation may enter into a maintenance agreement for facilities for Private Area Lighting Service provided that the Customer signs a TMI and provides a TMI Deposit as set out in Schedule "C" prior to maintenance work commencing. Any difference between the TMI Deposit paid and the actual cost incurred by the Corporation shall be either invoiced or refunded to the Customer.

8.0 Joint Use Service

Joint Use Service shall, by separate agreement, be made available to electrical or communication utilities in areas in which the Corporation provides Service, for leasing of space on existing Corporation transmission and distribution poles, where sufficient space is available, and in accordance with specific terms and conditions outlined in a contract with each Joint Use Service Customer.

9.0 Service Conditions**9.1 Point of Delivery:**

Any Point of Delivery for Service shall be at a location approved by the Corporation.

When metering is appropriate, Service shall be provided to the Customer through a single meter and each individual unit within a multiple dwelling building will be served as a separate Point of Delivery, unless the Corporation agrees otherwise.

Where the Corporation and a Customer have agreed that Service to a Multiple Unit Dwelling shall be delivered through a single Point of Delivery, the applicable General Service rates will apply to the Service.

All meters and associated equipment connected to the Point of Delivery shall be

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owned and maintained by the Corporation.

9.2 Mobile Homes and Multiple Unit Dwellings:

Service shall normally be provided to mobile homes and units of a Multiple Unit Dwelling through separate Points of Delivery, based on the applicable Residential Service rates.

Where a common Point of Delivery exists for a number of mobile homes or units of Multiple Unit Dwelling, billing shall be at the applicable General Service rates.

Service provided to common use areas (e.g., laundry facilities) for a number of mobile homes or units of Multiple Unit Dwelling shall be separately metered and billed at the applicable General Service rates.

9.3 Customer Facilities:

The Customer shall, at his own cost, provide and maintain, in good repair and condition, in a location, approved by the Corporation, suitable accommodation for the Corporation Facilities required for the supply of Service at the Point of Delivery. All Customer Facilities from the Point of Delivery into the Customer's premises shall be provided and maintained by the Customer in accordance with applicable statutes, regulations, standards and codes and any directions given by the Corporation. The Customer shall be responsible for providing suitable devices to protect the Customer's service entrance and equipment connected thereto from overload, single phasing and abnormal voltage or supply conditions.

The Corporation is entitled to limit the size and nature of equipment installed by a Customer at a service location in order to control voltage fluctuations if, in the Corporation's opinion, acting reasonably the equipment could adversely affect the Corporation's Facilities or operations.

9.4 Interference:

The Customer shall not interfere with any Corporation Facilities.

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The Customer shall permit the Corporation to manage vegetation on the property owned or controlled by the Customer to maintain proper clearances and reduce the risk of contact with the Corporation's Facilities.

9.5 Delay in Taking Service:

If, with respect to an application to extend Corporation Facilities to any Point of Delivery, the Corporation has reason to believe that the provision of Service to that Point of Delivery will not be taken within 30 days after Service is available, then the Customer shall pay, as a precondition of Service to such Point of Delivery, the amount of the Maximum Corporation Investment as determined in accordance with Schedule "A" for the type of Service provided.

Upon commencement of Service and payment by the Customer for Service, the additional amount paid by the Customer on account of the Maximum Corporation Investment shall be refunded.

9.6 Customer Extensions

A Customer shall not extend Customer Facilities beyond property owned or occupied by the Customer.

9.7 Extension of Service

Subject to Section 9.6 of these Terms and Conditions, if the Corporation's estimated cost of extending Customer Facilities at the request of a Customer is less than the Maximum Corporation Investment specified in Schedule "A" for the type of

Service provided, the Customer will not be required to make any construction contribution.

In all other cases, an agreement providing for payment of the extension charges in excess of the Maximum Corporation Investment in respect of such extension, calculated in accordance with Schedule "A", shall be a precondition to the Corporation's commencement of work on such extension.

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If the Corporation determines that it is necessary to install Corporation Facilities to provide a requested Service that are different from the Facilities that the Corporation typically installs to provide Service, the Customer will pay the costs for such materials and equipment.

9.8 Underground Service Extensions:

The extension of underground distribution facilities shall be undertaken subject to the conditions set out in Schedule "B" and shall be subject to the Maximum Corporation Investment and required Customer Construction Contribution as determined in accordance with Schedule "A".

9.9 Conversion from Overhead to Underground Service:

When a Customer requests that existing Corporation Facilities be converted from overhead to underground, the Customer shall pay, in advance, the estimated cost to be incurred by the Corporation in connection with the conversion, including but not limited to the following:

- a) the original capital cost of the existing Corporation Facilities being removed, less accumulated depreciation; plus
- b) the estimated cost of removing the existing Corporation Facilities, less the estimated salvage value; plus
- c) the estimated cost for the installation of the new underground Corporation Facilities, less any applicable increase in the Maximum Corporation Investment calculated in accordance with Schedule "A".

Any difference between actual and estimated costs shall be invoiced or refunded to the Customer without interest.

9.10 Relocation of Facilities:

If the Customer wishes to relocate any Corporation Facilities, the Customer shall provide an alternate location and valid permit satisfactory to the Corporation and shall pay to the Corporation, in advance, the estimated costs of the

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upgrade/relocation. Upon completion of the upgrade/relocation, any difference between the actual and the estimated costs shall be invoiced or refunded to the Customer.

10.0 Rights of Way and Access to Facilities**10.1 Easements:**

The Customer shall grant, or cause to be granted, to the Corporation, without cost to the Corporation, such easements or rights-of-way over, upon or under the property owned or controlled by the Customer as the Corporation reasonably requires to provide Service to such Customer.

10.2 Right of Entry:

The Corporation's employees or agents shall have the right to enter a Customer's property with the exception of residential areas at all reasonable times for the purpose of installing, maintaining, monitoring and removing the Corporation's Facilities and for any other purpose incidental to the provision of Service.

The Corporation shall have the right to enter a Customer's property at any time for the purpose of dealing with any emergency situation relating to or posing a threat to persons, property, Corporation Facilities, and/or the provision of Service.

After termination of the Service to any Customer, the Corporation shall have the right, at reasonable times, to enter onto the Customer's land and premises to remove the Corporation's Facilities.

The Customer shall provide the Corporation with reasonable access to Corporation Facilities located on the Customer's property.

10.3 Access to Meters

The Customer shall provide and maintain reasonable access to the Corporation to all metering equipment for the purpose of changing, servicing and reading such equipment. Where the Customer's Service address or location is generally

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locked during normal business hours, the Customer shall provide the Corporation with a key to permit access to the meter.

If the Corporation informs a Customer that reasonable access to metering equipment is not being provided, then the Customer must take immediate action to remedy the situation. If the Customer fails to remedy the situation within a reasonable time the Corporation, at its sole discretion may estimate consumption until the situation has been remedied in which case the Customer shall be billed on the basis of the Corporation's estimates; or

- a) remedy the situation on behalf of the Customer and apply the costs to the Customer's next regular billing; or
- b) discontinue Service in accordance with Section 16 of these Terms and Conditions of Service.

11.0 Metering**11.1 Installation:**

The Corporation shall provide, install and seal all meters necessary for any measurement in connection with the Service supplied to a Customer, unless otherwise specifically provided in a contract with the Customer.

Any metering equipment used by the Corporation shall be installed, connected, operated and tested in accordance with the applicable statutes, regulations, standards, and codes

Each Customer shall provide and install a Measurements Canada approved meter receptacle or other facilities suitable for the installation of the Corporation's meter or metering equipment.

The Corporation may replace meters from time to time at its discretion.

11.2 Location:

The Corporation and the Customer will determine a reasonable location for a

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meter, and the Customer will make the location available for the installation of the meter.

In selecting a meter location, the parties will, among other things, have regard for applicable statutes, regulations, standards and codes, the type of Service required and convenience of access to the meter. The Customer will ensure that the meter is reasonably accessible to The Corporation.

Meter receptacles shall be installed on the exterior of single family detached and Multiple Unit Dwellings, row housing and other similar dwellings. Where more than one meter is to be installed, the meters shall be grouped in a suitable location on the exterior of the building.

Meter receptacles shall also be installed on the exterior of buildings that are closed during normal working hours such as churches, arenas, sewage stations, summer cottages, seasonal commercial buildings, etc.

Meter receptacles shall not be installed in locations that are not readily accessible or likely to become inaccessible by the construction of fences, garages, or other types of structures.

Meter receptacles installed on the exterior of buildings shall be located and maintained at a point not less than 1.6 metres or more than 1.8 metres above finished grade (measurement taken to meter face).

Meter receptacles installed in pedestals for trailer courts or parks shall be located at a point not less than 1.6 metres or more than 1.8 metres above finished grade (measurement taken to meter face). In the case of single meter pedestals, the meter receptacle shall be installed such that it faces the road.

Meter receptacles may be installed indoors for Customers receiving General Service unless they are components of approved metering modules and shall be installed at a height not less than 1.2 metres or more than 1.8 metres above the finished floor (measurement taken to meter face).

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Meter receptacles installed on switchboards in multiple unit dwellings may be installed at a minimum height of 45 cm above the finished floor provided that the room in which the switchboard is located is used solely as a mechanical or electrical room. Where a meter is installed on a Customer-owned pole, the pole shall be provided and maintained by the Customer as required by the Canadian Electrical Code and any other applicable legislation.

If the Corporation informs a Customer that meter receptacles have not been installed and maintained within these guidelines, then the Customer must take immediate action to remedy the situation. The Corporation may discontinue Service to a Customer if the Customer fails to remedy the situation within the time provided for in the notice to the Customer, or the Corporation may, following notice to the Customer, move the meter to a location acceptable to the Corporation and include the costs associated with moving the meter to the Customer's next regular bill.

11.3 Meter Tests and Adjustments:

A meter may be inspected by the Corporation at any reasonable time, and shall be inspected and tested upon the written request of a Customer, provided the request is accompanied by a Meter Accuracy Test Deposit as set out in Schedule "C". Meters shall be tested or calibrated by an official designated by the Department of Measurement Canada and Corporate Affairs (Canada) or such other government department as may from time to time be charged with that responsibility.

In the event that the test of the meter discloses that it is not accurate within the limits prescribed by the *Electricity and Gas Inspection Act* S.C. 1980-81-82-83, the Meter Accuracy Test Deposit paid by the Customer shall be refunded to the Customer and the billings to the Customer based upon readings of the inaccurate meter shall be adjusted to correct for the error. Unless an examination of past meter readings or other information discloses the time at which the error commenced, then the error shall be deemed to have commenced on the date

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which is three months prior to the date of the testing of the meter or the date upon which the meter was installed or last tested, whichever occurred later.

In the event that the test of the meter discloses that it is accurate within the limits prescribed by the *Electricity and Gas Inspection Act* S.C. 1980-81-82-83, and regulations, standards or guidelines thereunder, The Corporation shall charge the Customer the Meter Accuracy Test Fee set out in Schedule "C" equal to the Corporation's actual cost of having the meter tested less the Meter Accuracy Test Deposit paid by the Customer.

11.4 Energy or Demand Diversion:

If under any circumstance a person prevents a meter from accurately recording the total Demand or Energy supplied, the Corporation may disconnect the Service without notice and take other appropriate actions.

The Corporation may then estimate the Demand and amount of Energy supplied but not registered at the Point of Delivery. The Customer shall pay the Corporation for the cost of the estimated Demand and Energy consumption plus all costs related to the investigation and resolution of the Service diversion.

12.0 Meter Reading and Billing**12.1 Meter Readings and Estimates:**

In the case of metered Services, the invoices for Service provided to the Customer shall be based upon actual meter readings. In circumstances where the Corporation is not able to obtain meter readings for any reason including, without limitation, locked doors, weather conditions, vandalized equipment, or equipment failure, invoices for Service shall be based upon meter readings estimated by the Corporation. These estimates will be adjusted if and when actual meter readings are obtained.

Should the meter reading be disputed, the Customer shall pay the amount described as owing in the invoice. Upon certification of the meter reading, the Corporation will make all necessary adjustments.

DRAFT TERMS & CONDITIONS OF SERVICE**12.2 Billing Adjustment:**

Notwithstanding that bills are required to be paid in full, the following billing adjustments shall apply.

a) Over-billing:

The Corporation will refund to the Customer any amount which the Corporation incorrectly collected for the entire duration of the over-billing on the Customer's next bill following the discovery of the over-billing. If the duration of the over-billing cannot be determined with reasonable accuracy, the amount refunded will be the amount of the over-billing for the 3 months prior to the discovery of the over-billing.

b) Under-billing:

The Corporation will invoice the Customer for any amount which the Corporation incorrectly did not collect from the Customer for the entire duration of the under-billing, up to a maximum period of 12 months. If the duration of the under-billing cannot be determined with reasonable accuracy, the amount invoiced will be the amount of the under-billing for the 3 months prior to discovery of the under-billing.

Notwithstanding the above; the adjustment period for under-billing will be for the entire period, regardless of the length of time, if the Customer has tampered with the meter or the Corporation Facilities, or has otherwise used Service provided by the Corporation in an unauthorized way.

If an instance of under-billing to a Customer's account is due to negligence or willful misconduct on the part of the Corporation, no adjustments will be made to the Customer's account for that instance of under-billing.

In all cases of adjustments to under-billed accounts, The Corporation shall determine reasonable terms of repayment. The repayment shall be interest free and in equal installments corresponding to the Corporation's

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normal billing cycle. Section 12.6 of these Terms dealing with late payment charges will apply if the repayment schedule is not adhered to.

Adjustments for over-billing or under-billing will not be made to closed accounts with positive or negative balances of \$5.00 or less.

12.3 Payment of Accounts:

Accounts in respect of charges for Service shall be sent on a monthly basis to Customers by the Corporation and the accounts become payable in full.

- ~~a) where the accounts are delivered by hand to the Customer the day they are so delivered;~~
- ~~b) Where the accounts are sent by mail to the Customer, 21 days following the billing date on the invoice; or~~
- ~~c) Where the accounts are faxed or delivered by electronic mail, 24 hours after they are sent.~~

Failure to receive a bill does not relieve a Customer from the obligation to pay the amount owing for any Service provided by the Corporation. Late charges shall apply pursuant to Section 12.6 of these Terms.

Should any billing by the Corporation be disputed, the Customer shall pay the full amount described as owing in the invoice. Upon certification of the billed amounts, the Corporation will make all necessary adjustments.

In addition to payments for Service, the Customer is required to pay to the Corporation the amount of any tax or assessment levied by any tax authority on Service provided to the Customer (e.g., Goods and Services Tax).

~~Partial payments on an account will be applied to the unpaid amounts outstanding on the oldest bills first.~~ Partial payment by a Customer in no way eliminates the Customer's requirement to pay the total unpaid amount outstanding on a power bill.

DRAFT TERMS & CONDITIONS OF SERVICE**12.4 Collections Administration Fee:**

The Corporation shall commence collection action when accounts are past due. When collection action is initiated, the Administration Fee for Commencing Collection Action set out in Schedule "C" may be assessed for initiating the collection action to the Customer's account to partially recover the administrative cost of said action.

12.5 Proration of Initial and Final Billings:

An amount payable to the Corporation for a Customer Service Charge, Demand Charge or Facilities Charge will not be pro-rated. These charges shall be applied in full for any initial or final billings. The Corporation may, at its sole discretion, choose to waive these charges for billings of less than seven days where there has been no consumption of electricity by the Customer.

Final Billing charges totalling less than \$5.00 will not be billed to a Customer.

12.6 Late Payment Charge:

The Corporation shall, in addition to other charges, impose a late payment charge computed at a rate of one and one-half (1 1/2) per cent per month (19.562% per year) on the balance in arrears, for accounts which are not paid within 7 days after the account becomes payable.

12.7 Dishonoured Payments:

An additional administrative charge equivalent to that charged by Chartered Banks may be assessed to reflect the administrative cost of processing any dishonoured payment. Dishonoured payments include cheques returned by the Customer's bank for any reason such as non-sufficient funds (NSF), stale dated, body and figures differ, unsigned, closed account, cheque cannot be traced, etc.

Following the receipt of three (3) dishonoured payments from a Customer, the Corporation shall notify the Customer that only cash, a money order or certified cheque will be accepted for payment.

DRAFT TERMS & CONDITIONS OF SERVICE**12.8 Outstanding Charges:**

The Corporation may add to a Customer's bill charges authorized by these Terms and owing to the Corporation by the Customer, including Construction Contribution, TMI and any charge set out in Schedule "C".

13.0 Corporation Responsibility and Liability**13.1 Continuous Supply:**

The Corporation shall make all reasonable efforts to maintain uninterrupted Service to its Customers, but the Corporation cannot guarantee uninterrupted Service. Customers requiring a high degree of security of supply or power quality are required to provide their own backup or standby facilities.

Where a plant or any part of a plant malfunctions and the Corporation is unable to supply Service, the Corporation shall, with due regard for cost and circumstance:

- a) promptly make repairs; and
- b) pending repairs, take all reasonable steps to supply Service from other sources if other sources are reasonably available.

The Corporation shall, whenever possible, give the Customer reasonable notice of any anticipated interruption of Service and will endeavour to ensure that such interruptions are as short and infrequent as circumstances permit.

13.2 Limitation of Corporation Liability:

The Corporation shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind (including legal and other professional fees and disbursements), whether direct or indirect, which the Customer may suffer, sustain, pay or incur (collectively, "Losses") arising out of or in any way connected with (i) any use of Service by the Customer, or (ii) any failure, defect, fluctuation, reduction or interruption in the provision of Service by the Corporation to the Customer, other than Losses for direct physical loss, injury or damage to a

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Customer or a Customer's property to the extent resulting directly from the negligent acts or omissions or willful misconduct of the Corporation, its employees or agents).

Notwithstanding any other provision contained in these Terms, the Corporation shall not be liable for any indirect, special, exemplary, punitive or consequential nature, including without limitation loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, loss of opportunity, cost of purchased or replacement capacity or Energy, cost of capital, business interruption, loss of use of any facilities or property, claims of a Customer's customers, contractors or other third parties, or any other similar damage, expense, cost, liability or loss whatsoever.

14.0 Customer Responsibility and Liability

14.1 Required Permits, Licenses and Authorizations:

The Customer shall ensure that all required permits, licences, and authorization are provided to the Corporation prior to:

- a) commencement of Service;
- b) any change of service requirements at any point of delivery; or
- c) commencement of construction of new service extensions.

14.2 Customer's Facilities:

The Customer shall be responsible for the installation and condition of all Customer's Facilities on the Customer's side of the Point of Delivery, except metering or other equipment owned by the Corporation.

14.3 Customer's Installation and Operation:

Any Customer Facilities supplied with Service shall be installed in accordance with the applicable statutes, regulations, standards and codes and only after the Corporation has given its consent and any necessary inspections have been successfully completed such equipment will be operated so as to cause no interference with the Corporation Facilities or with any other Customer's Service. The Customer will be responsible for costs associated with installing,

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maintaining, repairing and replacing the Customer Facilities.

14.4 Improper Operation or Installation:

Should the Customer fail to comply with Section 14.3, the Corporation may immediately suspend the supply of Service. Service will be recommenced when this failure is remedied to the satisfaction of the Corporation.

14.5 Customer's Protection:

The Customer shall be responsible for determining whether any devices are needed to protect the Customer's equipment from damage that may result from the provision of Service by the Corporation. The Customer shall provide and install any such devices.

14.6 Notice of Service Change:

The Customer shall provide the Corporation with reasonable prior notice of any significant change in the Customer's Connected Load to the Service which is supplied. Notwithstanding any other provision of these Terms, the Corporation shall not be obligated to supply any Demand in excess of that agreed to by the Corporation.

14.7 Damage:

The Customer shall be responsible for all damage caused to Corporation Facilities located on the Customer's premises where the damage is caused by the negligent acts or omissions or wilful misconduct of the Customer or anyone permitted by the Customer to be on the premises. At the Corporation's sole discretion, the costs associated with such damages will either be added to the Customer's regular bill or will be billed on a separate invoice issued to the Customer.

14.8 Changes to Corporation Facilities:

If the Corporation must modify its Corporation Facilities to accommodate a Customer load or Service change, the Customer shall pay for all costs in connection with such modification including the following costs:

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- a) the original capital cost of the existing Corporation Facilities being removed, less accumulated depreciation and any amount paid by the Customer as a customer contribution toward those Corporation Facilities; plus
- b) the Corporation's estimate of the cost of removing the existing Facilities, less the estimated salvage value of those Corporation Facilities; plus
- c) the Corporation's estimate of any other costs that may be associated with the removal of the existing Corporation Facilities.

Any difference between the actual costs incurred and the estimated costs shall be refunded or invoiced to the Customer.

14.9 Service Calls:

If the source of a Customer-requested service call is the Customer Facilities, the Customer may be required to sign a TMI and to provide a TMI Deposit prior to any work being undertaken by the Corporation.

Following satisfactory completion of the service call, the Customer will be invoiced or refunded the difference between the TMI Deposit paid and the actual costs incurred by the Corporation.

If the Corporation responds to a request by the Customer for Service of Customer Facilities, then the Corporation may charge the Customer a service call response fee as set out in Schedule "C", whether or not the Corporation installs, maintains, repairs, or replaces any Customer Facilities.

15.0 Termination of Service by Customer

15.1 Notice:

Except where otherwise provided in a contract between the Corporation and a Customer, a Customer may, at any time, give the Corporation ~~reasonable~~ written notice 5 business days, in advance, that the Customer wishes Service to the Point of Delivery terminated. Upon receipt of such notice, the Corporation shall read the Customer's meter within a reasonable time, and shall use its best efforts

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to read the Customer's meter at the time requested by the Customer. A Customer shall be liable for all amounts owing in respect of Service provided to the time of such reading.

Where the Customer's account is connected to a third party property and/or asset (e.g., User Pay Customers and the Northwest Territories Housing Corporation), the Corporation will make reasonable efforts to contact the third party.

15.2 Early Restoration:

If permanent Service is terminated at the request of a Customer, whether or not the Service is disconnected by the Corporation, and if the same Customer requests restoration or reconnection of the Service to the premises on the same rate classification (or any replacement thereof) within 12 months, the Corporation shall require the Customer to pay the greater of:

- a) the expenses the Corporation incurred in making the restoration or reconnection of the Service; or
- b) the sum of the Demand charges which would have been paid by the Customer between the time of termination and the time of restoration or reconnection of the Service on the applicable rate.

16.0 Termination of Service by Corporation**16.1 Reasons of Safety:**

The Corporation may, without notice, terminate Service to a Customer where, in the Corporation's opinion acting reasonably:

- a) the Customer's equipment or premises are unsafe or may become dangerous to life or property;
- b) the use of the Service may cause damage to the Corporation's Facilities, or interfere with, or disturb Service to any other Customer; or
- c) the Customer Facilities or any equipment of the Customer fail to comply with applicable statutes, regulations, standards and codes.

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The Corporation will reconnect the Service when the safety problem is resolved, the Customer has provided the Corporation with an electrical inspection report of the Customer Facilities at the Customer's sole expense, the Corporation, acting reasonably, has approved such inspection report and the Customer has provided, or paid the Corporation's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance.

16.2 Without Notice:

The Corporation may, without notice, terminate a Customer's Service or install a current-limiting device to restrict the Service to such Customer where:

- a) the Customer is subject of bankrupt, insolvency or a similar proceeding, enters into receivership, or ceases to be a corporate entity;
- b) in the Corporation's opinion acting reasonably, tampering has occurred with any equipment used to provide Service, any meters, any seals, or any other Corporation Facilities;
- c) the Customer makes fraudulent use of the Service being provided; or
- d) the Customer changes Service requirements without the permission of the Corporation.

16.3 Non-payment:

Where accounts are not paid by a Customer within 7 days after the accounts become payable (a total of 28 days after the billing date), the Corporation may ~~give~~ issue a ~~48-hour~~ notice of disconnection of Service for non-payment, in writing to the Customer. Where accounts are not paid before the expiration of such notice, the Corporation may forthwith disconnect the Customer from Service.

Where the payment is received prior to the disconnection being completed is ultimately determined to be a dishonoured payment, the Corporation will not be required to initiate a second ~~48-hour~~ disconnection notice and may proceed with disconnection action as appropriate.

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Where accounts are not paid by a Customer before the expiration of a notice given to the Customer pursuant to this section, the Corporation may forthwith disconnect the Customer from Service and may refuse to reconnect the Customer for Service until the accounts in arrears, a security deposit payable under Sections 5.7 and 5.8, and a reconnection fee as set out in Schedule "C" are fully paid. As an alternative to disconnection during winter months, the Corporation may, at its sole discretion acting reasonably, ~~install a device to~~ limit the electricity available to the Customer.

16.4 Removal of Facilities:

Upon termination of Service, the Corporation shall be entitled to remove any of the Corporation Facilities located upon the property of the Customer and to enter upon the Customer's property for that purpose.

17.0 Miscellaneous**17.1 Waiver:**

Any waiver by the Corporation, or failure of the Corporation, to exercise any of its remedies will be limited to the particular instance, and will not constitute a waiver of any other rights or remedy or extend to any other matter under, or in any way affect the validity or modify the meaning or intent of, any provisions of these terms. The exercise by the Corporation of any remedy provided for by these Terms will not operate to prevent the Corporation from pursuing any other remedy to which it is entitled.

17.2 Compliance with Applicable Legal Authorities:

The Corporation and the Customer are subject to, and shall comply with, all existing or future applicable federal, territorial and local laws, all existing or future orders or other actions of governmental authorities having jurisdiction.

17.3 No Assignment:

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A Customer shall not assign any of its rights or obligations under the Terms without obtaining the Corporation's prior written consent. Any assignment in violation of this Section shall be void.

SCHEDULE "A" MAXIMUM CORPORATION INVESTMENT

1. "Capital Cost" is defined as the estimated cost of materials, labour, equipment, expenses, and any other direct costs incurred by the Corporation in extending Service to a Point of Delivery.

"Annual Cost" is defined as including:

- a) the fixed annual amount of return and depreciation in respect of the Capital Cost of Facilities constructed to serve the Customer;
 - b) costs of generating and transmitting electric energy to the Customer, and operating and maintaining Facilities constructed to serve the Customer; and
 - c) administrative and general costs incurred by the Corporation in providing Service to the Customer.
2. Subject to the provisions of Section 3 of this Schedule "A", the maximum cost which the Corporation will incur to extend Service to a Point of Delivery (herein referred to as the "Maximum Corporation Investment") shall be determined as follows:
 - a) for Residential Service:
 - i) \$1,500 per single family dwelling;
 - ii) \$750 per unit in a Multiple Unit Dwelling;
 - b) for General Service;
 - i) where the estimated life of the Service Extension is at least 25 years, \$250 for each anticipated kilowatt (kW) of Billing Demand which shall not be less than 5 kW; or
 - ii) where the estimated life of the Service Extension is less than 25 years or where Service will be Seasonal, \$200 for each anticipated kW of Billing Demand (which shall not be less than 5 kW), multiplied by the amount determined by the following calculation:

DRAFT TERMS & CONDITIONS OF SERVICE**Estimated number of months during which Service will be received****25 years X 12 months per year**

- (c) for Industrial Service, in the manner specified in an agreement with the Industrial Customer.
3. The Corporation will refund a portion of the construction contribution within three (3) years of the original service connection date, provided that:
 - a) actual kW demand is significantly higher than the kW demand used to determine the contribution and no changes have been made to the Facilities related to such contribution; or
 - b) another Customer shares a part of the service to which the construction contribution relates.
 4. If the construction contribution refund is a result of an additional Customer applying within three (3) years of the original service connection date to be served from a service extension for which a construction contribution was originally made, the construction contribution will be reapportioned and refunds made as follows:
 - a) The Maximum Corporation Investment is re-evaluated by adding the costs of that portion of the dedicated facilities related to the original Customer to the portion of the dedicated facilities related to the additional Customer(s);
 - b) The Corporation's re-evaluated maximum investment is applied against the total costs of the shared service extension;
 - c) The difference between the Corporation's re-evaluated maximum investment and the total cost of the shared service extension is the total amount of the construction contribution required from the original Customer and the additional Customer(s);
 - d) The additional Customer(s) is then assessed an apportioned amount of the revised construction contribution required taking into consideration the portion of the original line that is now shared and the amount of time that

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has lapsed since the original service connection date of the original Customer serviced by the service extension (depreciation is based upon the Average Life Group method (ALG)); and

- e) The original contributor will be refunded the difference between the original construction contribution made and his portion of the revised total construction contribution required.

The refund program ceases to exist after Facilities have been in Service for a period of three (3) years from the time of the original Service connection.

The refund will be paid to the original contributor unless the Corporation is directed in writing by the original contributor to make the refund payable to another.

Action for the refund of capital contributions must be initiated by the original contributor.

If all or part of a contribution is subsequently refunded, the appropriate amount of GST originally collected will also be refunded.

DRAFT TERMS & CONDITIONS OF SERVICE**SCHEDULE "B" CONDITIONS OF UNDERGROUND SERVICE**

- 1). The Corporation shall extend Electricity Service by underground conductor lines upon and subject to the following terms and conditions (the term "developer" as used herein means the person or party who has requested the underground Service):
 - a) No Service is then available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the Corporation) will be connected to such extension (the "underground service area"), each of which is situated upon a parcel of land upon which other single family dwellings in the underground Service area are situated;
 - b) All permanent Service in the underground Service area shall be provided exclusively through underground conductor lines;
 - c) The developer shall provide, without cost to the Corporation, such rights-of-way, easements, utility corridors and transformer locations as the Corporation may require for the installation, operation and maintenance of such extension, which the developer shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the Corporation in installing, maintaining or removing its Facilities;
 - d) The Corporation shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the Corporation in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the developer;
 - e) Service, for purposes other than Residential use and Municipal Street Lighting, may be provided from such extension only with the consent of the Corporation;
 - f) In relation to the underground Service, the developer shall cause to be provided a meter receptacle and Service conductor protection from not less than 60 centimeters below grade level to the line side of the meter receptacle and will ensure the installation of a Service having 200 ampere

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capacity;

- g) The developer shall provide to the Corporation a certified copy of the registered plan of subdivision and final construction plans showing the location and elevation of sidewalks, curbs and gutters, and underground utilities together with such evidence as the Corporation may reasonably require to the effect that all rules and regulations applicable to the development have been or will be complied with by the developer;
- h) Survey stakes indicating grades and property lines shall be installed and maintained by the developer;
- i) The surface of the ground for a distance of not less than 1.5 metres on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;
- j) Unless otherwise agreed to by the Corporation, the developer shall provide a survey for the location of transformers, street light bases and cable routing, as required; and
- k) Sidewalks, curbs and gutters may be constructed by the developer but no other permanent improvements shall be made until approved by the Corporation.

In addition, the Service shall be subject to such other conditions as may be specified by the Corporation from time to time.

DRAFT TERMS & CONDITIONS OF SERVICE**SCHEDULE "C" FEES AND SERVICE CHARGE SUMMARY****CONNECTION FEES**

5.1 Residential Service Connection Fee	\$20.00
5.1 General Service Connection Fee (where a Demand Meter is Required)	40.00
5.1 Temporary Service Connection Fee	40.00
5.1 Seasonal Service Connection Fee	40.00
5.2 Reconnection Fee	40.00
5.2 Reconnection Fee after hours	300.00

5.8 Security Deposit

RESIDENTIAL SERVICE \$300.00

USER PAY \$100.00

GENERAL SERVICE

An estimate equal to the 2 months of billings with the highest consumption during the next 12 month period.

LATE PAYMENT AND DISCONNECTION

12.6 Late Payment Charge	1½ %/Month
12.4 Administration Fee for Commencing Collection Action	35.00
12.7 Dishonored Payments ~~(as per Chartered Bank Charges)~~	25.00

Miscellaneous Fees/Charges

5.6 Power Bill Copying Charge	\$2.00 <u>per request</u>
11.3 Meter Accuracy Test-Deposit	\$75.00
11.3 Meter Accuracy Test-Fee (accurate meters only)	TMI
14.10 Service Call Response Fee	\$40.00 or TMI
7.5 Private Area Lighting Maintenance Fees	TMI
9.7 Service Extension Charges	As per Schedule "A"
9.9 Overhead to Underground Conversion	As per Schedule "A"
9.10 Relocation of Facilities	TMI
2.33 TMI Deposit	
-100% of the estimated TMI or \$100.00 whichever is greater	