Q. With reference to Hydro’s response to IC-NLH-014 in this GRA, please provide a complete copy of the 1998 KPMG Depreciation Policy Study referred to in Hydro’s response to CA-NLH-32 in the 2012 Hydro Depreciation Application.

A. Please refer to IC-NLH-150, Attachment 1.

KPMG

NEWFOUNDLAND AND LABRADOR HYDRO

DEPRECIATION POLICY STUDY

1998

FINAL REPORT

KPMG

Final Report

NEWFOUNDLAND AND LABRADOR HYDRO DEPRECIATION POLICY STUDY 1998

FINAL REPORT

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October 7, 1998

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I

Introduction

The objective of this study was to review the depreciation policies, methods and procedures of Newfoundland and Labrador Hydro ("NLH"). NLH commissioned this study in preparation for an expected future rate referral to the Public Utilities Board ("PUB").

The current study updates an earlier report prepared by KPMG, entitled "Depreciation Policy Study." That earlier report was submitted to NLH on January 12, 1987.

The issues to be addressed in the current report are as follows:

- Should NLH continue to use the sinking fund depreciation method for a large portion of its assets?

- What approach should NLH take in estimating and accounting for the net salvage value and predicted site restoration costs of assets?

- Are the service lives that are currently used by NLH for estimating depreciation expenses appropriate?

- Which of NLH's assets shall be considered "prime assets", and therefore depreciated as total plants, rather than depreciating each of their components item by item?

To address these issues, a five-pronged work plan was followed. The components of our work plan were as follows:

- We surveyed Canadian electrical power utilities with respect to their depreciation policies and practices. This included a review of their service life estimates and their practices regarding the recognition of net salvage values. We also conducted interviews with U.S information sources pertinent to these subjects.

- We undertook a review of the regulatory and academic literature on the subject of depreciation policies in general, and U.S. practices in particular. A special focus of this review was a review of current approaches to accounting for salvage.

- We reviewed NHL's actual historical data on disposals and retirements.

- We prepared a financial model of the assets of NLH. We used this model to project the future financial impacts of possible changes in NLH's depreciation methods. In particular, we examined the impacts of a potential change to Straight line depreciation for those asset classes that are currently depreciated using the sinking fund method.

- Acres International conducted an engineering review of the physical condition of key Hydro assets and a review of Hydro's maintenance policies that are considered to affect service lives.

Our 1997 study differed from the 1986 study in the following ways:

- We have paid particular attention to the issue of accounting for net salvage revenues or costs. Since 1986, considerable concern has arisen over the financial penalties associated with plant decommissioning and site restoration, which represent negative salvage values. Net salvage values have been impacted by changes in environmental regulations on the one hand, and changes in the market for used utility equipment on the other.

- We conducted, to the extent possible, a more detailed review of NLH's actual experience with retirements and disposals. At the time of the previous study, NLH's oldest assets were only 20 years old, and, accordingly, yielded little data on retirement experience. More data were available for this study.

II

Alternative Depreciation Methods

All depreciation methods seek to allocate the capital costs of an asset over its service life.

In this chapter, we discuss the two major methods of depreciation that have been used by the electric utility industry. We outline the advantages and disadvantages of each. The two methods are:

- The straight line method.
- The sinking fund method.

These two methods differ in the timing of depreciation expenses: they each lead to a different level of total capital-related costs over the life of the assets.

There are also other methods, used for specific purposes or for special assets:

- Declining balance depreciation is normally used for income tax purposes.
- Unit of production depreciation is used for assets related to depleting commodities.
- Amortization, unrelated to service lives, is used when service lives cannot be easily tracked.

The last three depreciation methods are not discussed in detail.

A. The objectives of a depreciation policy

In preparation for evaluating alternative depreciation policies, we outline the primary objectives of depreciation policies in general. These objectives are sometimes in conflict, and the policies must be designed so as to achieve an appropriate balance among them.

1. Rationality

Accounting policies for depreciation must be justifiable and rational. They should provide a defensible allocation of the capital costs of an asset over its useful life. The concept of rationality emphasizes that the allocation of costs must be based on defensible principles, i.e., it should not be arbitrary.

2. Inter-generational equity

The concept of intergenerational equity states that rate payers who receive a benefit from a facility (e.g., in the form of electric power) should pay the full costs of that facility. Future rate payers should not pay the costs associated with facilities or services that benefited rate payers in earlier periods. Similarly, rate payers of earlier periods should not pay for benefits that will accrue to future rate payers.

3. Clarity

The notion of "clarity" captures the idea that accounting procedures should make the assumptions underlying the calculation of depreciation expenses as explicit as possible.

4. Simplicity

Simplicity refers to the requirement that accounting procedures should be straight-forward and readily understandable.

5. Computational convenience

Depreciation procedures that are computationally convenient involve fewer accounting entries and depreciation calculations than more complex, but perhaps theoretically superior, approaches. The desire for computational convenience often, but not always, complements the desire for simplicity.

6. Conservatism

Conservatism is the desire to adopt accounting treatments that will tend to under-report utility income (or, alternatively, over-estimate revenue requirements). Conservatism reflects a desire to minimize negative "surprises". By biasing accounting treatments towards an under-reporting of utility income, conservatism minimizes the likelihood that write-offs against a utility's net worth will have to be taken in the future. In the field of depreciation, an emphasis on conservatism will tend to favour accounting treatments that yield larger estimates of depreciation expenses.

The desire for conservatism can conflict with the desire for an appropriate matching of costs and revenues. The concept of conservatism usually implies that depreciation charges should be levied sooner rather than would be suggested by the "most likely" expectations associated with a facility.

B. The straight line depreciation method

The most widely used depreciation method in Canada and in the United States is the straight line method. In this method the original cost of the asset is spread over its service life in equal installments, i.e., the amount of depreciation is the same in each year and equals the original cost of the asset (net of salvage) divided by its estimated service life.

This method is currently used almost exclusively by seven of Canada's ten largest electric utilities. The other three utilities are:

- Newfoundland and Labrador Hydro, which uses the sinking fund method for hydraulic generation, transmission and substation assets.
- Hydro Quebec, which uses the sinking fund method for all assets, except some categories of equipment.
- New Brunswick Power, which uses the sinking fund method for its nuclear plant.

Exhibit II-1 summarizes the major depreciation practices in Canada.

In the United States 207 of the 216 largest electric utilities[1] are using the straight line depreciation method for all of their assets. It is of interest to note that the vast majority of the U.S. electric utilities are privately owned. Those that use sinking fund depreciation are primarily the government-owned exceptions. In Canada, only two of the ten top electric utilities (in Alberta) had been owned by private investors in the past, and were only recently joined by a third (Nova Scotia Power). They, as the U.S. private utilities, use almost exclusively straight line depreciation..

As noted above, depreciation is used to accumulate an amount over the lifetime of an asset that will equal its original acquisition cost less any net salvage that occurs when the

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[1] *With annual revenues in excess of $1 million.*

Exhibit II - 1
Depreciation methods

	Straight Line	Sinking Fund	Declining Balance	Unit of Production	Amortization	Changes Planned:
NS Power	All assets.					None
NB Power Corp.	Most assets.	Nuclear generating station.				None
Hydro-Quebec	Construction, research and work equipment.	Fixed assets, n.e.s., depreciated @ 3% annual compound rate.				Studying the idea of using straight-line for some more fixed assets.
Ontario Hydro	Most assets.		Transport & work equipment, and minor computer equipment.			None
Manitoba Hydro	All assets.					None
Sask. Power	All assets.					None
Alberta Power Corp.	Most assets.			Coal leases.		None
Transalta Utilities	Most assets.				Accounts for which the tracking of retirements is impractical: computer H/W & S/W, and office furniture & equipment.	None
BC Hydro	Most assets.		Motor vehicles.			None

asset is retired. As the depreciation associated with the fixed asset is gradually accumulated over its service life, through depreciation charges built into the customers' rates, the outstanding debt associated with a particular fixed asset or group of assets declines, and so does the interest related to the debt. The top diagram in Exhibit II-2 shows the sum total of depreciation and interest related to an asset to which straight line depreciation is applied. It can be seen that as the net book value of the asset declines over time due to its accumulated depreciation, the amounts of interest charged to the customers also decline. Consequently, customers who use the particular assets in the early part of the assets' service lives pay a higher total of depreciation and interest than the customers in the late years of the assets' service lives.

Since an asset provides the same service to the customers in its early years as in its late years, the straight line depreciation method violates the principle of equity between today's and tomorrow's customers.[1]

It has been argued that the equity among customers is restored by the fact that the maintenance expenses associated with a fixed asset may be substantially higher in later years than in earlier years. The sum total of depreciation, interest and maintenance expenses may therefore not change very much over the years under the straight line method. This is most likely to be true for certain types of equipment or plant, such as transportation and work equipment, diesel generating units, control equipment or buildings. Even though we could find no study that quantified these relationships, the justification of higher depreciation plus interest in an asset's earlier years, with offsetting higher maintenance expenses in its later years, appears to be qualitatively justifiable for assets with such characteristics.

There are many categories of fixed assets, however, for which maintenance expenses clearly do not increase consistently with age. If applied to these assets, straight line depreciation does not appear to provide a fair and equitable system of charges to the utility's customers in the long term, in so far as the system penalizes today's and benefits tomorrow's customers.

Other categories of assets for which straight line depreciation may have significant advantages are those that are subject to rapid technological change. Prime examples are computers and telecommunications equipment. The value of such assets is continually declining in today's environment, as cheaper, more powerful products enter the market. For such assets the argument that today's user should pay the same amounts as tomorrow's user is therefore no longer valid, as the costs of obtaining a particular service from a computer or telecom asset are declining over time in the overall marketplace. The

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[1] *In fact, due to inflation, it would be fully justified for "tomorrow's customers" to pay more for the use of an asset in its late years, rather than paying the same as in its early years, or - even worse - paying less, as is the case under straight line depreciation.*

straight line depreciation method, with its declining total of depreciation and interest, reflects that process.

C. The sinking fund depreciation method

The sinking fund method of depreciation is based on the principle that total capital charges, which are defined as the total of depreciation and interest expenses, should remain constant over the service life of an asset. In contrast, in the straight line method it is only the depreciation component of the total capital charges, embedded in electricity rates, that remains constant over the asset's service life, while the interest component declines over time (see tope diagram in Exhibit II-2).

The bottom diagram in Exhibit II-2 shows total capital charges (the total of depreciation and interest) over the service life of a fixed asset when the sinking fund method is used.

In that method, the sum of interest and depreciation, expressed as a percentage of the original capital cost of the asset, is defined as the "Capital Recovery Factor." It is higher than the interest rate. The difference between the Capital Recovery Factor and the interest rate is defined as the Sinking Fund Factor.

In the explanation of the sinking fund method provided below, for the sake of simplicity, no salvage value is assumed.

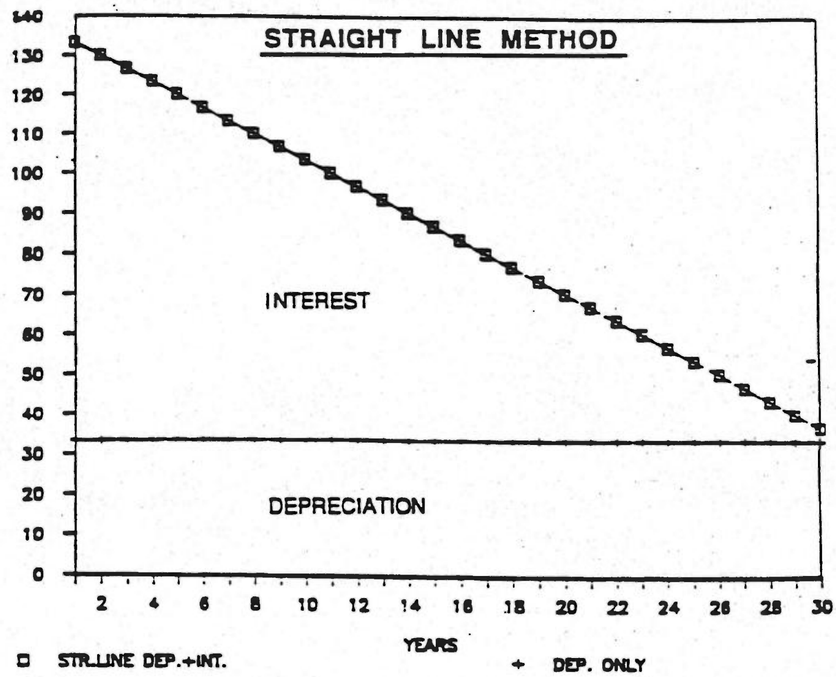
In the first year of the asset's service life the utility's customer pays interest on the original acquisition cost of the asset plus the depreciation component of the capital charge, which is equal to the original cost times the Sinking Fund Factor. In the next year, the interest component of the capital charge that has to be paid by the customer is reduced from the previous year's interest component by an amount that equals the interest associated with the first year's depreciation. In the third year the interest component that has to be paid by the customer is reduced again from the previous year's interest component by the amount of interest associated with the previous year's depreciation. At the same time, the depreciation components increase by exactly the same amounts as the decline in the interest components. This continues until the end of the asset's service life, when the accumulated depreciation equals the original acquisition cost of the asset.

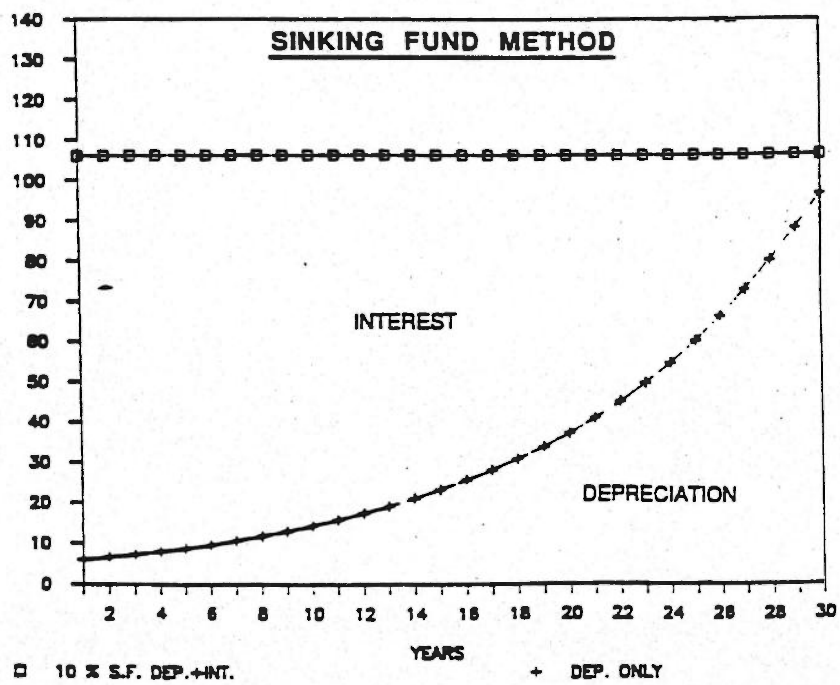
Thus, as the interest charged to the utility's customers in their rates gradually declines over time, the difference between the constant total annual capital charge and the declining interest expense is made up by an ever-increasing depreciation expense. Whereas in the first year most of the capital charge is represented by interest and only a small part is represented by depreciation, in the last year most of the charge is depreciation, with interest being only a small part of the total.

The sinking fund method of depreciation eliminates the inequities created across customer generations by the straight line method. The sinking fund process is similar in

Exhibit II-2

DEPRECIATION AND INTEREST ON $ 1,000





nature to the ways in which homeowners make annual mortgage interest and principal payments, paying the same total amount in the first and in the last month of their multi-year mortgage term, with interest making up most of their first payment and the repayment of principal making up most of their last payment.

The shape of the curve shown in the lower diagram of Exhibit II-2 depends on the interest rate used in the calculation of the Capital Recovery Factor and Sinking Fund Factor. The higher the interest rate the sharper will be the bend in the dividing curve between depreciation and interest in the diagram, and the greater will be the difference between the sinking fund and the straight line depreciation methods. When the interest rate is zero the two methods are identical.

In fact, the straight line depreciation method can be regarded as a special case of the sinking fund method pertaining to a zero interest rate.

In contrast to straight line depreciation, which is a simple but arbitrary method of allocating the costs of an asset to the years of its service life, the sinking fund depreciation method has a real rationale. When that method is applied to an asset, the net book value of the asset will always reflect the value that would make a second-hand buyer of the asset in the middle of its service life financially indifferent to the alternative of buying the particular second-hand asset (Alternative A) or buying an equivalent new one (Alternative B). Assuming that the remaining service life of an asset accurately reflects the time at which the buyer of the asset would have to replace it, the time difference between that replacement and the replacement of a new asset would be exactly equal to the time that the used asset has already spent in service. It can be easily shown that the difference between the discounted present values of the replacement costs of the second-hand asset (Alternative A) and the replacement costs of the equivalent new asset (Alternative B) is exactly equal to the accumulated depreciation under the sinking fund method. Consequently, the buyer would be indifferent to the choice of buying a used asset at its net book value, or buying an equivalent new asset at its original acquisition cost.

In brief, the net book value of an asset that is depreciated in accordance with the sinking fund method reflects the true financial value of the asset at all times, and its annual depreciation reflects the true decline of that value, as the asset moves closer to replacement.

C. Conclusions

The sinking fund method of depreciation provides greater equity among present and future users of electric power, as it allows the power users to derive the same net benefits from the use of a particular asset throughout its entire service life.

The only two justifications for a higher total of depreciation and interest expense during the early years of an asset, from the perspective of equity among customers, would be:

(1) an expected increase in maintenance costs over the asset's lifetime, and

(2) declining value due to technological advances and obsolescence.

Such trends are experienced for certain types of machinery, equipment and buildings.

III

Accounting for Net Salvage Value

In this chapter we discuss alternative approaches to accounting for the net salvage value of utility assets. We also review the survey responses received on this issue.

A. Definition of net salvage value

In examining the salvage value of utility assets on retirement, the following terms are relevant:

- **Gross salvage** is the revenue received from the sale of an asset or from the sale of the associated materials (i.e., scrap value).

- **Retirement costs** are costs associated with removing an asset, in preparation for either resale or disposal. They also include the costs of restoring a site to its original condition or to the condition mandated by applicable environmental laws and regulations. Retirement costs can also be referred to as "disposal", "site restoration", or "decommissioning" costs.

- **Net salvage** equals **Gross salvage** less any **Retirement costs**. In other words, net salvage represents the net proceeds received by a utility on the retirement of an asset, taking into account all decommissioning costs or other removal costs.

Net salvage can be either positive or negative, depending on the particular circumstances. Increasingly, utilities are finding that, for many assets, net salvage values are negative.

Negative net salvage occurs when the costs associated with removing an asset are greater than the revenues received from recovered materials. (These revenues may be derived from the material's scrap value, resale to other users, or re-use in other parts of the company.)

B. Alternative accounting approaches

Alternative approaches to accounting for the net salvage values related to a retired asset are as follows:

1. Ignore salvage values in the calculation of the asset's depreciation rate. Recognize gross salvage revenue as income and retirement costs as an expense at the time the asset is retired.

2. Ignore salvage values in the calculation of the asset's depreciation rate and include the net salvage incurred on the retirement of the asset in the depreciable cost base of the asset that replaces the retired asset.

3. Ignore salvage values in the calculation of the asset's depreciation rate and amortize the net salvage incurred on the retirement of the asset over a period following the retirement.

4. Alternatively, incorporate the asset's predicted net salvage value in the calculation of its depreciation rate.

5. Establish a separate reserve (or allowance) for net salvage for each account that is expected to have negative net salvage. Calculate and display this reserve separately from accumulated depreciation.

The advantages and disadvantages of these accounting approaches are discussed in the sections below.

1. Ignore salvage values in the calculation of depreciation

The first approach is to ignore salvage values in the calculation of the depreciation rate. The net salvage value is then treated simply as an addition to utility revenues or expenses (depending on the sign) in the year incurred.

When net salvage values are positive, this approach can be justified on the basis of its conservatism: depreciation expense during the life of an asset will be overstated, since it does not take into account the positive net salvage value that will be received on retirement. In the year of retirement, utility customers will see a one-time benefit in the form of a boost to utility net income.

A decision to ignore salvage values in calculating depreciation can sometimes also be justified on the basis of expediency. When net salvage values (whether positive or negative) are small, either in dollar amounts or as a percentage of the assets' original cost, the mis-statement of depreciation that may result from this accounting treatment is of limited significance relative to the benefit of reduced accounting complexity and uncertainty. Unadjusted depreciation expenses can be based on the known and fixed initial capital cost, without having to make uncertain estimates of future salvage values.

A special case in which salvage values can be ignored without much loss of accuracy is that of assets with relatively shorts lives, which are purchased and retired in large quantities in a regular fashion each year. The best examples are vehicles, as discussed below.

If an allowance were to be made for salvage in the calculation of the depreciation rates of a vehicle, the cash received for "trading in" the vehicle would largely offset the remaining undepreciated book value on disposal (assuming that the original salvage revenue estimates were reasonably accurate), i.e., the write-up on disposal would largely equal the corresponding write-off.

An alternative approach is to ignore any adjustments to the depreciation rates on account of salvage, i.e., record higher depreciation amounts for a particular vehicle each year, but also record, as income, the trade-in amount received for the vehicle on disposal. Because of the regularity of purchases and retirements, the two alternatives produce, with a very good approximation, the same bottom lines in each year, as the higher depreciation expenses aggregated across the fleet, are offset by the trade-in revenues received for the vehicles retired in the particular year.

For that reason, there is no practical advantage to choosing the more complex accounting option over the option of simply ignoring salvage values in the calculation of depreciation for vehicles, and recognizing the actual cash received for the traded-in vehicles as income.

Similar considerations apply to several other types of assets, such as computers or furniture.

The notion of expediency is less compelling when retirements become less regular and net salvage values become large, especially if they are also negative. When net salvage values are negative, ignoring them in the calculation of depreciation expenses cannot be justified on the basis of conservatism and if they are, in addition, significant in both absolute and percentage terms, other alternatives are more appropriate.

Such alternatives would re-establish the principle of intergenerational equity, as the beneficiaries of a utility's investment in plant and equipment would shoulder all of the costs associated with that plant throughout its use..

Alternatives that fulfill that objective are described in the next sections.

2. Add negative net salvage costs to the depreciable cost base of the replacement asset

Under this approach, net salvage costs are added to the depreciable cost base of the asset that replaces the one that is retired.

When a major asset is replaced by a new asset of the same nature at the same site (rather than abandoned), site restoration or rehabilitation is not required. The existing site will still be occupied by the new asset (most likely in an upgraded or improved form). Salvage will include the removal costs of the asset that is replaced, which will normally take place as part of the construction activities related to the new asset. In most cases it would actually be quite hard to separate the costs of the two activities.

In the case of negative net salvage the rationale for this treatment is the assumption that any such salvage is most likely to be offset by construction cost savings attributable to the fact that the site has been previously occupied by a similar asset. A positive net salvage value would indicate that the retired asset, or part of it, was still in usable condition at the time of retirement and could have been used by NLH's future power users if it hadn't been replaced. It is, therefore, equitable to (1) charge future power users with the costs that enabled them to apply savings to the acquisition and construction costs of the new asset and/or (2) compensate them for having lost the use of the previous asset.

3. Amortize negative net salvage costs over a future period

Under this approach, negative net salvage values are amortized against utility net income over a future period of, say 5 to 10 years.

At first sight, this alternative may appear to violate the goal of intergenerational equity, as rate payers in subsequent periods would bear the costs associated with a facility that benefited rate payers in earlier periods. However, in the cases in which this alternative may be used, there would not be any inequity, as explained below.

The setting up of an after-the-fact amortization account might be applied, as the only feasible alternative, when:

- there are significant net decommissioning costs that are too large for being ignored by the application of Alternative 1, and
- the asset will be completely removed and not replaced at the same site, which makes the use of Alternative 2 impossible, and

- the retired asset, which is going to be decommissioned, has passed most of its service life, making it impractical to apply adjustments to its depreciation rates (see Alternatives 4 and 5 further below).

When an asset is not replaced at the same site, the most likely reason for abandoning, rather than replacing it, is normally the result of a feasibility study that has clearly shown that other options are more economical. In other words, the reason for not replacing the asset is the conclusion that the functions it performed can be better performed by new plant and equipment, added to the system **elsewhere**. It is reasonable to assume that the feasibility study that has produced that conclusion would have included the consideration of the decommissioning costs of the old site in its calculations.

If that was indeed the case, it would be the new generation of power users who would benefit from the utility's choice, and from the fact that the old asset was not replaced at the same site. As the consideration of the site restoration costs was part of the most economical choice, those costs can be deemed to contribute to the best deal for the future power users, and can be legitimately charged to them without generating any intergenerational inequity.

4. Incorporate salvage values in the depreciation rate.

An often used option is to incorporate net salvage values in the calculation of depreciation rates. Under that method the depreciation expense reflects both the initial cost of the asset and the final salvage value (be it negative or positive).

This approach serves the objective of providing intergenerational equity in a continual manner. It can be applied to new assets when depreciation bases and rates are established for them. It is also possible to apply this approach to an existing asset in service, if warranted by changed circumstances, as long as the asset has not yet passed a large portion of its service life.

The allowance for salvage can be incorporated in the depreciation rate in the form of a mark-up or mark-down. Accordingly, if applied to sinking fund depreciation and negative salvage, the reserved "prepaid" amounts will be quite low in early years and increase over time. This is quite in order, as the growing accumulated depreciation reserve, attributable to the salvage component of the depreciation rate, will reduce debt and corresponding interest expenses. The growing interest savings will increasingly benefit the rate payers. Consequently, intergenerational equity will be preserved when the amount of depreciation mark-up increases over time, offsetting the increasing interest saving.

In the case of straight line depreciation simple mark-ups or mark-downs will cause the same intergenerational inequity as the basic (constant) depreciation amounts themselves, as explained in Chapter II.

In the United States, where the subject of generating plant decommissioning has gained substantial importance in recent regulatory proceedings, some regulators (Florida Public Service Commission, Public Utility Commission) recognized this principle and require the salvage-related amounts that are added to the basic annual depreciation expenses to be calculated on a sinking fund basis. Most other regulators accept the straight line method for calculating salvage allowances. However, they generally do not allow the incorporation of inflation into the estimation of the expected site restoration costs. Instead, those costs must be calculated at the price levels of the year of acquisition, as a percentage of acquisition costs. There is little, if any, logic in this approach, but it appears to be common practice in the U.S.

Considering that the large majority of generating stations, substations or transmission lines will probably not be decommissioned in the foreseeable future, it is unclear what will happen to the amounts of money collected from the rate payers in anticipation of site restoration costs when the plant reaches the end of its service life and remains in operation, or is replaced at the same site without the predicted negative salvage costs being incurred.

The major problem with the approach described above is the presumably rare incidence of power stations or other major facilities being decommissioned in a complete manner, with their sites being sold or released by the utility to other users. Consequently, while the method of considering salvage in the form described in this subsection may suit the circumstances in a minority of retirement cases, it is expected to create problems in the majority of cases in the form of over-recovery of depreciation.

It can be concluded that as the inclusion of estimated net salvage values in depreciation rates may potentially imply significant problems, this approach should be limited to assets which:

- are large in absolute terms,
- have a significant net negative salvage value in percentage terms,
- do not fit any of the previous alternatives.

5. Establish a separate reserve for net salvage values

The incorporation of salvage in the depreciation rates combines two types of costs that have different characteristics:

- They reflect the historical fixed costs of the assets, which are known with certainty (even though the life span of the assets may not be).

- They reflect estimates of future salvage values, which are as yet unknown and, therefore, much less certain. The uncertainty of future salvage values is caused partly by the uncertainty of future market conditions and is further amplified by changing environmental regulations that cannot be easily predicted 30 or 40 years in advance.

Because of the different nature of the associated costs (historical capital costs vs. future salvage costs), it is theoretically preferable to account for these costs separately, i.e., to accrue net salvage costs separately from historical capital costs.

Such an approach is conceptually attractive. It provides for more "visibility" than the procedure discussed under Alternative 4, i.e., the incorporation of salvage values into the calculation of the depreciation rate. It also provides more information to the users of the utility's financial statements.

The "bottom line" impacts of this treatment of accumulating the appropriate salvage reserve are identical to those of Alternative 4, both on the shareholders and on the rate payers. The only difference may be in the presentation of the financial statements: while in Alternative 4 the reserve would be embedded in the Accumulated Depreciation reserve on the Asset side of the Balance Sheet, in Alternative 5 it may be shown as a "rehabilitation reserve" (or a similar item) on the Liability side.

Because of its explicit nature, this alternative is particularly attractive when the establishment of a decommissioning reserve satisfies public sensitivities, such as associated with the licensing of nuclear generating plants.

C. Current practices among surveyed utilities

The surveyed Canadian electric power utilities follow a wide range of procedures for incorporating salvage value into their financial statements. Each of the procedures outlined in the preceding part of this chapter are used by at least one of the respondent utilities in some circumstances.

All the surveyed utilities, except NLH and Hydro Quebec, consider net salvage values, either as an input to their calculation of depreciation rates, or as the basis for the calculation of a separate decommissioning reserve for at least some of their assets. NLH and Hydro Quebec are the only Canadian electric power utilities that currently do not consider salvage values in their depreciation procedures for any of their assets

Exhibit III-1 summarizes the utilities' practices in a tabular form.

Several utilities establish a separate reserve, independent from accumulated depreciation, to account for negative net salvage costs. This approach is generally adopted for assets with large decommissioning costs, such as nuclear and some coal-fired generating stations. The following utilities use this approach for such assets:

- New Brunswick Power Corporation.
- Manitoba Hydro.
- Saskatchewan Power.

Most other Canadian utilities (and, for smaller assets, the ones listed above) build salvage values into the depreciation rates of certain assets, as indicated in Exhibit III-1. As noted, Hydro Quebec and NLH are the exceptions.

Hydro Quebec is the only utility that follows Alternatives 2 and 3. When an asset is replaced, Hydro Quebec adds negative net salvage costs to the depreciable balance of the replacement asset. In the event that an asset is not replaced, the net costs of retirement are classified as special components of accumulated depreciation and are depreciated over the next ten years, using the sinking fund method.

Practices of U.S. electric power utilities regarding salvage were reviewed in the relevant literature. The findings are reported in Appendix A.

D. Estimates of net salvage value

In this section, we compare the assumptions used by the surveyed utilities regarding the net salvage value of plant and equipment. Expected net salvage values (in future inflated terms) are expressed as percentages of the original (uninflated) acquisition cost of each type of asset and are defined as "net salvage factors:. Only four utilities provided us with detailed assumptions:

- Nova Scotia Power.
- Manitoba Hydro.
- Alberta Power.

Exhibit III - 1
Salvage policies

	Method for Estimating Salvage Value	Treatment of Estimated Future Positive/Negative SV's	Examples of Asset Classes that have Reported Negative SV	Recent Changes:
NS Power	- Decommissioning studies for generation facilities. - Based on own past experience for other assets.	- Incorporate in depreciation rate.	- Generation assets. - Transmission assets other than conductors. - Distribution assets other than transformers. - General property other than vehicles, office furniture & computing equipment.	None
NB Power Corp.	- Estimated only for nuclear & thermal generating stations, and vehicles.	- Generating stations: establish a decommissioning reserve with separate accrual expense. - Distribution assets: amortize. - All other assets: expense when retired.	- In all asset classes, except vehicles.	- Amortization of distribution assets applies to all distribution assets.
Hydro-Quebec	- Zero salvage assumed for depreciation accounting.	- *Non-replacement of asset:* net costs of retirement are capitalized in a special "control account" and amortized over 10 years using the SF method. - *Replacement of asset:* undepreciated costs are capitalized in a special "control account" and amortized over 10 years using the SF method. Dismantling costs and net salvage costs are added to the replacement cost of new assets.	- No data.	None
Ontario Hydro	- Engineering estimates.	- Rarely factored into depreciation rates. - When significant and certain: estimated provisions are treated as an annuity and accumulated in a special account on the balance sheet. The annuity is charged to depreciation expense and interest is charged to interest expense. Primarily used for the decommissioning costs of nuclear stations. Otherwise salvage charged to depreciation expense when incurred.		None

Exhibit III - 1, continued
Salvage policies

	Method for Estimating Salvage Value	Treatment of Estimated Future Positive/Negative SV's	Examples of Asset Classes that have Reported Negative SV	Recent Changes:
Manitoba Hydro	- Engineering estimates and own past experience.	- Incorporate net salvage values in calculation of depreciation rate, except for negative SV of thermal generation which is treated as a separate reserve.		None
Sask. Power	- Own estimates for all asset classes, except for vehicles & buildings. Vehicles & buildings: salvage value equals market value at retirement.	- Establish a decommissioning reserve for all types of assets where relevant, except vehicles & buildings. - Vehicles and buildings: salvage values included in depreciation rates.	- All asset classes, except buildings & vehicles.	Salvage values were removed from depreciation rates in 1996 - replaced by de-commissioning reserve.
Alberta Power Corp.	- Decommissioning studies and own experience.	- Incorporate in depreciation rate.	- Generation, transmission, distribution equipment.	None
Transalta Utilities	- Engineering estimates and own past experience.	- Incorporate in depreciation rate.	- Generation, control, transmission and distribution equipment. - Transformers. - Mines.	None
BC Hydro	- In-house depreciation studies and own past experience. - Engineering estimates. - Comparisons with other utilities.	- Depreciation rates are set in consideration of asset life, anticipated maintenance costs and net salvage value. The selected depreciation rate results in the asset's net book value being reduced to its salvage on retirement. - In general, actual gains or losses (including differential net salvage) from the retirement of individual assets are added to depreciation expense for the year. They are recognized as part of the group depreciation procedures for quantitative and mass assets.	- Primarily transmission and distribution equipment.	None

- TransAlta.

Negative net salvage values are becoming increasingly common. One utility (New Brunswick Power) reports that all asset classes, except vehicles, experience negative net salvage.

Nova Scotia Power reports negative net salvage for most properties, with the following exceptions:

- Conductors.
- Transformers.
- Vehicles.
- Office furniture.
- Computing equipment.

1. Hydraulic assets

The net salvage factors assumed for hydraulic assets show great variations.

Manitoba Hydro assumes a net salvage factor of -10% for all of its hydraulic assets.

Nova Scotia Power, in contrast to some of the other utilities, assumes very small negative net salvage factors (from 0% of -1.1%) for its hydraulic assets.

2. Thermal generation

Manitoba Hydro currently assumes a net salvage factor of 0% for its thermal generating stations (in other words, its retirement costs are estimated to equal gross salvage values).

The other utilities that responded to the survey show negative net salvage factors for thermal assets ranging from -1.4% to -17.3%.

3. Transmission

The surveyed utilities show negative net salvage factors for most transmission equipment.

For certain types of transmission equipment, reported salvage factors varied widely across the surveyed utilities. For wood poles, for example, these ranges were reported:

- Manitoba Hydro: -10%.
- Nova Scotia Hydro: -15%.
- Alberta Power: -25% to -35%.

The utilities listed above show similar net salvage assumptions for steel towers.

Compared to the other utilities, Alberta Power is very conservative (or pessimistic) in its assumptions of the net salvage value of overhead conductors. A factor of -55% is assumed, vs. -2.5% for TransAlta and -5% for both Nova Scotia Power and Manitoba Hydro. It is interesting to note that the two privately owned Canadian utilities are the ones that use very high negative salvage factors. It is also significant that these high factors were actually approved by the regulator in Alberta.

3. Distribution

As with transmission equipment, a wide range of net salvage factors is assumed for distribution equipment. Net salvage percentages for poles and fixtures range from -20% for Nova Scotia Power to -50% for Alberta Power.

Transformers represent one category of the few distribution assets for which positive net salvage is assumed by some utilities. Nova Scotia Power assumes a 15% net salvage factor, while Alberta Power assumes 14%.

Alberta Power assumes significant positive net salvage factors for some assets, such as street and highway lights (+40%).

4. General assets

Each of the utilities that responded show significant positive net salvage factors for vehicles. As noted earlier in this report, these other utilities also assume significantly longer service lives for vehicles than Newfoundland and Labrador Hydro. Salvage factors for vehicles range from 10% to 30%.

As an example for all of the above, TransAlta's approved salvage factors (or salvage "percentages" or "rates") are shown in Exhibit III-2. They all relate to the procedure of building salvage factors into the depreciation rates.

Exhibit III-2

TransAlta
Recommended 1996 Net Salvage Rates

Line	Class of Plant	(1) Recommended Net Salvage Percentage	(2) Currently Approved Net Salvage Percentage
1	**Hydro Production**		
2	Ghost	0.1%	-0.5%
3	Horseshoe	-51.7%	-30.5%
4	Kananaskis	-15.7%	-10.7%
5	Cascade	-23.8%	-21.6%
6	Bearspaw	-4.9%	-1.7%
7	Barrier	-23.3%	-6.2%
8	Spray	-8.6%	-11.1%
9	Three Sisters	-51.0%	-70.5%
10	Rundle	-31.8%	-24.0%
11	Interlakes	-39.8%	-27.6%
12	Pocaterra	-27.5%	-16.0%
13	Seebe General	174.4%	66.3%
14	Brazeau	-15.1%	-14.3%
15	Bighorn	-23.9%	-15.8%
16	**Steam Production**		
17	Wabamun	-11.4%	-18.2%
18	Sundance	-5.1%	-6.4%
19	Keephills	-2.9%	-3.0%
20	Sheerness	-2.4%	-3.4%
21	**Environmental Control**		
22	Wabamun	-8.2%	-15.0%
23	Sundance	-10.4%	-10.5%
24	Keephills	-14.2%	-14.1%
25	Sheerness	-5.1%	-4.1%
26	**Coal Mines**		
27	Wabamun	-4.6%	-4.5%
28	Sundance	-5.3%	-6.3%
29	Keephills	-3.9%	-3.2%
30	Sheerness	-2.5%	-1.2%
31	Mining Equip	-6.0%	-5.0%
1	**Transmission**		
2	Transmission Lines	-24.9%	-31.5%
3	Substations	-11.1%	-9.3%
4	Telecontrol System (w/o SCC)	3.8%	5.9%
5	System Control Center	3.0%	2.0%
6	**Distribution Systems**	-50.4%	-45.6%
7	**General**		
8	Computer Systems	10.0%	20.0%
9	General Equipment and Vehicles	14.0%	9.4%
10	Meters & Transformers	-40.6%	-35.0%
11	Buildings	0.0%	0.0%

F. Conclusions

This subsection summarizes our recommendations regarding the application of the alternatives defined above. The summary is also presented in graphical form in Exhibit III-3.

It is recommended that for assets with an original acquisition cost of less than $500,000 and for all assets that have an estimated future salvage value (in inflated terms) of less than 10 percent of their acquisition cost (in original terms) salvage should be recognized in NLH's Income Statement at the time it is incurred. This treatment is defined as Alternative 1.

For assets that have acquisition costs in excess of $500,000 **and** an estimated net salvage values in excess of 10 percent (referred below as "major" assets), the following alternatives exist:

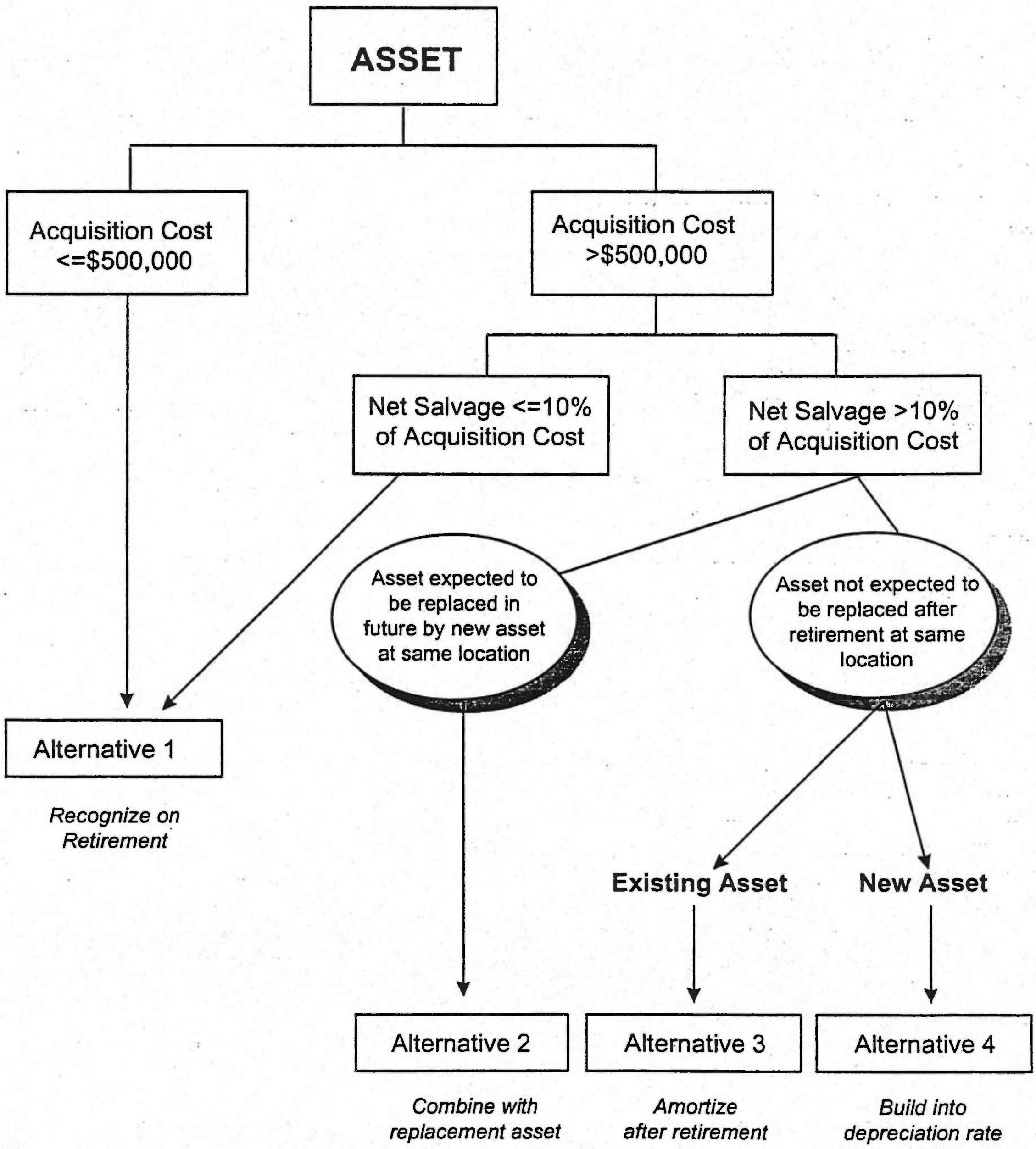
- When the asset is expected to be replaced after retirement by an asset of the same nature at the same site (most likely in an upgraded or improved form) the net salvage value related to the retired asset should be combined with the acquisition and construction costs of the new asset. As explained earlier, this approach is equitable because (1) future users are expected to enjoy capital cost savings attributable to the pre-existence of a plant at the site and (2) future users are deprived from the use of still useable assets that were sold on disposal. The users of the replacement asset will therefore be (1) legitimately charged with the net retirement costs of the old asset and (2) legitimately credited with the proceeds gained from the disposal of the old asset or any part thereof. The treatment described in this paragraph is defined as Alternative 2.

- When a significant "major" asset is retired without replacement at the same site, and net salvage costs are incurred as a consequence of the asset's removal and/or the rehabilitation of its site, they can be treated in two ways:

  - If the decision to abandon a site was the result of a feasibility study that indicated that, after having included all removal and rehabilitation costs incurred at the old site into the study, the transfer of operations to a new site was still beneficial to NLH and its customers, it is equitable to charge future customers with the net salvage costs. That can be achieved by amortizing the costs over a period of five years for amortizable amounts of, say, less than $500,000, and ten years for larger amounts. This treatment is defined as Alternative 3.

  - When the removal of an asset and the rehabilitation of its site is performed as an undertaking or commitment related to external reasons, such as complying with urban or regional development plans, or satisfying public objectives, or responding to the terms of environmental and other approval

Exhibit III-3
Consideration of Net Salvage



processes, the net salvage costs should be built into the depreciation rates of the asset throughout its service life. This should be done in the form of a percentage mark-up on the depreciation rate calculated on the basis of the asset's original acquisition cost. The mark-ups or "salvage factors" can be calculated on the basis of engineering estimates. If properly calculated, they will produce a surplus in accumulated depreciation by the end of the asset's service life that is equal to the estimated net salvage costs in inflated terms. This treatment is defined as Alternative 4.

It is not practical to apply Alternative 4 to existing assets after they have passed a significant portion of their service lives. It is quite unlikely, however, that any of NLH's existing assets would fall into that category. If so, the application of Alternative 3 would be a logical option.

In theory, Alternatives 3 and 4 can also be used for the treatment of positive net salvage, the occurrence of which is expected to be rather exceptional for "major" assets.

The final alternative that was described in this chapter was Alternative 5. That alternative is identical in "bottom-line" terms with Alternative 4 but differs in presentation in NLH's financial statements. Alternative 5 consists of the establishment of an explicit reserve account for the accumulation of that portion of the depreciation reserve that is intended to cover future net salvage costs. It is used by utilities primarily when the establishment of a site rehabilitation reserve responds to public concerns. It is not likely that this alternative would be used by NLH.

IV

NLH's current property accounting practices

In this Chapter, we provide a description of NLH's current property accounting system. We also examine whether the system has any shortcomings and address the issue whether some enhancement of the system may be warranted.

A. NLH terminology

The following definitions are established by NLH in outlining its property accounting system:

- **Prime assets.** These assets represent major functional parts of the corporations' property, plant and equipment. Examples are individual thermal generating stations, individual transmission lines, individual substations and individual diesel plants.

- **Units of property.** These represent the main units of equipment or property contained within each prime asset. The unit of property is defined as a piece of equipment or structure that is independently operational, readily separable from the prime asset and useful in its own right. Examples of units of property are building foundations, dams, turbines, runners, wood pole structures, metal tower foundations, transformers, regulators, circuit breakers, diesel engines, steam turbine generators, boilers, etc.

- **Components of units.** Components of units represent parts or items making up units of property. Examples are transformer bushings, oil storage tank valves, fuel oil system pumps, cross arms, guys, etc.

The ways in which NLH uses these definitions in its property accounting system are discussed below.

B. The EPS system

The EPS system (Evaluation Programming System) is a mainframe computer system that is used by NLH to calculate the utility's depreciation expenses.

1. Records in the EPS system

The EPS system consists of a series of asset "records". These records define entries to the EPS system, where an entry represents a single piece of equipment, or pieces of equipment that are grouped together for the purpose of calculating depreciation expenses.

Each EPS record includes, among several other items, the following parameters:

- An asset start date.
- An initial net depreciable cost (original acquisition cost less grants in aid of construction).
- An assigned service life.
- A "depreciation rate". (This parameter is applicable only to plant and equipment depreciated according to the sinking fund method and is, in fact, the interest rate implied in the calculation of depreciation).

For each record, the EPS system calculates the annual depreciation expense and keeps track of accumulated depreciation and net book value. (Net book value equals the initial net depreciable cost less accumulated depreciation).

Total depreciation expense for NLH is simply the summation of the depreciation expenses calculated for each record in the EPS system. The EPS system is therefore the "core" of NLH's property accounting system.

2. The role of "capital work orders"

In many cases, a given record in the EPS system represents a particular "capital work order", where a work order is an individual request for a capital asset addition. The plant and equipment associated with a particular work order is considered to have started its service life on the date shown in the record.

The plant and equipment on a particular work order will be allocated to more than one record in the EPS system if that work order includes assets that are assigned different estimated service lives. The associated assets will then be appropriately divided up in the EPS system, so that each component can be depreciated at the appropriate rate.

C. Prime assets

As noted above, prime assets are major "functional" parts of the utility's property, plant and equipment. Examples are, as noted earlier, individual thermal generating stations, individual transmission lines, individual substations and individual diesel plants.

In the accounting system, however, there are significant differences among the various types of prime assets, as outlined below.

1. Hydraulic stations

Each individual hydraulic station is divided into units of property for the purpose of calculating depreciation. These component parts are assigned different service lives and, accordingly, must be assigned to different "records" within the EPS system. This is true even if these units went into service on the same date. Examples of units of property, along with their estimated service lives, include:

- Dams, dikes and intakes (100 years).
- Spillway and water regulating structures (75 years).
- Generator windings (25 years).
- Battery banks (15 years).

A list of units of property appears in Exhibit IV-1.

2. Non-hydraulic prime assets

Each non-hydraulic prime asset is depreciated using only one common service life for the units of property within the prime asset. For each such prime asset, all of the units of property that went into service on a particular date will therefore be grouped within one EPS record. (Thus, the EPS system contains very little detail on these accounts.)

Such prime assets include:

- Each thermal generating station.

Exhibit IV-1

NEWFOUNDLAND & LABRADOR HYDRO'S

FIXED ASSETS AND SERVICE LIVES

	Service Life	Method of Depreciation
Hydraulic Generation:		
Dams, dikes, intakes	100	Sinking Fund
Spillway and Water regulating structures	75	Sinking Fund
Surge tanks	50	Sinking Fund
Canals and tailrace channel	100	Sinking Fund
Penstocks	50	Sinking Fund
Turbines and governors	50	Sinking Fund
Generators	50	Sinking Fund
Generator windings	25	
Hydraulic valves	50	Sinking Fund
Gates	50	Sinking Fund
Stop logs, trash racks	50	Sinking Fund
Timber booms	20	Sinking Fund
Powerhouse crane	75	Sinking Fund
Auxiliary and reservoir power supplies	30	Sinking Fund
Static excitation system	25	Sinking Fund
Low voltage switching	50	Sinking Fund
Battery banks	15	Sinking Fund
Battery chargers	40	Sinking Fund
Station service electrical equipment	40	Sinking Fund
Control, metering & relayed equip.	30	Sinking Fund
Cable trays and conduit	40	Sinking Fund
Control and power cables	40	Sinking Fund
Forebay lines	30	Sinking Fund
Land improvements	60	Sinking Fund
Roads	50	Sinking Fund
Bridges	25	Sinking Fund
Fencing	20	Sinking Fund
Fire fighting system	25	Sinking Fund
Outdoor lighting system	25	Sinking Fund
Sewage disposal system	25	Sinking Fund
Water supply and storm drainage system, sump pump	25	Sinking Fund
Compressed air system	25	Sinking Fund
Cooling system	25	Sinking Fund
Underground storage tanks	25	Sinking Fund

Exhibit IV-1 (continued)

	Service Life	Method of Depreciation
Transmission: Steel Towers	50	Sinking Fund
Transmission: Wood Poles	40	Sinking Fund
Sub-Stations (High Voltage 69-230 kV)	40	Sinking Fund
Sub-Stations (Low Voltage 4.160-25 kV)	30	Straight Line
Distribution	30	Straight Line
Thermal Generation	30	Straight Line
Diesel	20	Straight Line
Gas Turbine	25	Straight Line
Vehicles	3 - 5	Straight Line
Telecontrol	10 - 20	Straight Line
General Plant:		
Mobile equipment	3 - 10	Straight Line
Office equipment	5 - 10	Straight Line
Tools & equipment	5	Straight Line
Test equipment	10	Straight Line
Buildings	20-36 & 50	Straight Line

- Each diesel plant.
- Each gas turbine plant.
- Each terminal station (substation).
- Each transmission line.
- Each telecontrol system.

The significance of a prime asset is two-fold:

- A given prime asset is the *minimum* level of detail which must be shown in the EPS system. For example, if a work order results in work performed on two separate prime assets, the associated costs will be divided among the two prime assets before entry into the EPS system. Additions to plant and equipment, when associated with one work order, generate one EPS entry, unless that work order results in additions to more than one prime asset.

- Additions to a prime asset are depreciated over the remaining life of that prime asset, unless the additions represent units of property that can be readily separated from the prime asset at the end of the prime asset's service life.

To illustrate the second point, we can examine additions to a thermal power station made when the station has 10 years of remaining life. Upgrades to the air-conditioning system at the thermal station will be depreciated over the 10-year remaining life of that station. This treatment reflects the fact that such upgrades cannot be readily separated from the underlying prime asset and, accordingly, will have no individual value of their own (other than possible salvage value) at the end of the prime asset's service life.

However, if a transformer is added to a substation, that has a remaining life of 10 years, it will be depreciated over the standard transformer life of 40 years. This reflects the fact that, although the substation has a remaining life of only 10 years, the transformer can be readily moved to another location if the station were to be decommissioned. Accordingly, it will provide an additional 30 years of service elsewhere after the station is retired. This treatment assumes that the station will go out of service at the end of the 10 year period.

Regarding partial retirements of sub-groups of assets within a prime asset, NLH will adjust the record in the EPS system to reflect the retirement of some of the plant and equipment associated with that record. NLH then reduces the depreciation by the amount of depreciation that actually had been incurred with respect to the assets removed. It does this by allocating the accumulated depreciation amount on a pro-rata basis between the assets retired and the assets continuing in service. This pro-rata allocation is based on the capital cost of the assets removed.

D. Mass property

NLH defines some types of plant and equipment as **mass property**. Examples are: insulators, conductors, wood poles, anchors, guys, etc.

The definition of mass properties has no impact on the EPS system, but does influence the grouping and type of information kept on these assets' original capital costs. (This information is kept within a separate PC-based accounting system.)

NLH's property accounting manual states:

> For mass property, separate plant accounts are established for each type of Unit of Property (e.g. insulators, conductors, etc.). On retirement, the average plant costs which prevailed at the date of installation, are written out of the plant accounts.

The mass property records are used to estimate the acquisition costs of "high quantity" types of assets on retirement. For example, if 1,000 insulators are removed from a transmission line, their costs, subtracted from the EPS records, are estimated from the mass property records, as it is virtually impossible to track the actual acquisition costs of the specific items that are removed.

E. Components of units

Components of units sometimes generate a separate EPS record when, for example, installed to replace a faulty component. At other times, the existing record of the unit of property or prime asset is adjusted.

F. Approaches to group accounting

As discussed in more detail in Chapter VIII and Appendix B, in conventional group accounting procedures, asset groups consist of assets that are "like" in character but did not necessarily go into service on the same date. Under Broad Group Procedures, groups are made up of all "like" assets, regardless of their date of in-service activation. Under Vintage and Equal Life Group (ELG) procedures, groups are made up of assets that are "like" in character and went into service in the same year.

NLH does not use such group accounting procedures. All other Canadian utilities use some form of group accounting for depreciation purposes for some of their asset categories.

G. Issues regarding NLH's depreciation accounting

The practice of grouping assets simply by work order number (or, effectively, by in-service date), may pose some problems from the perspective of creating the most informative accounting records:

- A prime asset record contains a large number of units of property of widely different characteristics (even though they are assumed to have the same estimated service lives). The grouping of the various units of property into one EPS record makes it difficult to identify the composition of the utility's total plant in terms of the various types of property. It would be difficult, for example, to determine the total acquisition costs of all of NLH's transformers, circuit breakers, etc., installed in a particular year, or in total.

- A work order corresponding to a major capital addition, such as a new thermal station, will result in a single asset entry of large dollar value. In terms of value, this entry will dwarf other entries in size. This creates an imbalance in the level of detail shown for different asset additions.

The second point above is particularly true for assets other than hydraulic stations. Hydraulic stations are broken down into a wide number of individual components with different estimated service lives. This tends to reduce the dollar value of individual asset records. NLH may consider the possibility of applying the same approach to other categories of generating stations, substations and/or transmission lines.

An example of the problem that arises when a diverse variety of items is lumped into a prime asset with a single service life, is the existence of units of property with significantly shorter services lives than that assigned to the prime asset. Battery banks, used in generating stations, are in that category. Battery banks in hydraulic generating stations, where they are treated as separate assets with unique records in the EPS system, have an assigned service life of 15 years (which was confirmed in our study as being the correct number). The same battery bank, in a thermal generating station or substation, would have an assigned service life of 30 years. Accordingly, most battery banks, when they are actually retired in a thermal generating station after about 15 years, are under-depreciated. The same applies to battery banks in substations.

The question arises whether specific items that have demonstrable shorter lives than the prime asset (such as the batteries noted above, or air conditioning units in buildings with 50-year lives) should be recorded and depreciated separately?

The answer to this question is related to materiality. From the retirement records of battery banks, we drew the conclusion that the total acquisition costs of all battery banks in NLH's plant is likely to be less than $1 million. Considering that the total acquisition costs of all generating and substations are close to $400 million, battery banks obviously make up a very small percentage of that cost. To illustrate this point, it should be considered that one single month of depreciation of NLH's thermal station and substations would pay for the entire capital cost of all battery banks in the system. Thus, if the actual service life of these prime assets were to be only one month longer than expected, that would more than offset +any error generated by the assumption of an overly long service life for battery banks.

With respect to larger units of property, in KPMG's 1986 Depreciation Study, a test was made with a typical transformer substation to assess the potential inaccuracy implied in the assignment of a single common service life to all assets in the station. In the test, Ontario Hydro's individual service lives were assigned to each type of equipment within the station rather than a single common number. The total depreciation expense that was calculated in that manner for the substation was very close to the depreciation calculated by using NLH's single depreciation rate for the entire prime asset. This led to the conclusion that the use of a single depreciation rate does not cause any material error.

A similar analysis was conducted by Acres International and is described in Chapter VII.

A problem may arise when a piece of equipment is replaced within a prime asset that has already been fully depreciated. In such a case, according to the rule of terminating the equipment's service life at the same time as that of the prime asset, the replacement item would have to be written off completely at the time of its installation. To respond to this problem the following recommendations are made:

- The occurrence of the problems above can be minimized by adjusting the service lives and depreciation rates of prime assets that are found to have longer than expected service lives, well before they are fully depreciated. Accordingly, when the time of retirement corresponding to previous estimates approaches, and it is obvious that the existing asset will be able to remain in service much longer, it is recommended that its service life be extended. As noted later in the report, such extension can be accomplished by conducting a Condition Survey of the prime asset, which will indicate the appropriate revised date for the asset's expected final retirement.

- When the cost of a piece of equipment replacing an existing equipment within a fully depreciated prime asset exceeds $50,000 it should be depreciated separately, using its own estimated service life. This approach implies that after the physical retirement of the prime asset the particular piece of equipment will still be suitable for re-use at another location.

- When the cost of the replaced equipment is $50,000 or less, it may be expensed (i.e., fully depreciated) on the date of installation.

H. Conclusions

As in the 1986 study, we consider NLH's current approach to depreciating prime assets appropriate.

NLH may consider **coding** its units of property in such a manner that it will be easy to determine the total number of like units and their total acquisition costs, by installation year, or in total. The coding would make it possible to compare the actual service lives of the assets with their assigned service lives on a statistical basis.

Many electric power utilities use a coding system defined as a Uniform System of Accounts, which identifies a particular type of asset (e.g. as a "current transformer", "compressor", "control cable", etc.). Such coding facilitates the statistical analyses required for a variety of purposes, and makes it possible to check accounting practices on a continual basis.

The service lives of major prime assets that approach the end of their previously estimated service lives but are expected to be able to remain in service much longer should be revised as soon as the need for a service life extension becomes apparent. Such service life extensions can be based on engineering Condition Surveys.

When a minor equipment is installed within a prime asset that has been fully depreciated it should be depreciated separately if its cost exceeds $50,000. If its cost is lower the minor equipment may be expensed.

V

Review of NLH's Retirements and Disposals

In NLH's EPS system individual asset records are not coded by equipment codes that describe the nature or the type of the asset (such as being a current transformer, a circuit breaker, etc.). Such codes are, in a generic way, specified in the electric utilities' uniform chart of accounts.

It is not possible, therefore, to determine how many pieces of equipment of a particular type (such as e.g., current transformers) are in NLH's **total plant** by vintage year. Consequently, it is not possible to determine, for example, the percentage of current transformers that were retired after a specific number of service years.

As noted, Newfoundland and Labrador Hydro may consider adopting a standard industry methodology for coding its property accounts. One widely-used accounting structure is that laid out in the "Uniform System of Accounts - Electric". This system of accounts was originally designed by the Federal Energy Regulatory Commission (FERC) in the U.S and is available from several sources, such as the United States Department of Agriculture.

Because of the absence of equipment codes (or "field codes"), only a limited analysis of retirements and disposals was possible in this study, which is described below.

A. Analysis of the retirement of vehicles

In spite of the lack of coding by type of equipment for assets in service, it was possible to perform an analysis of service lives for assets with relatively short lives, such as vehicles, battery banks, compressors and radio equipment. For those assets, it was possible to determine the dispersion of service lives, as on retirement both the acquisition date and the retirement date is recorded in NLH's records. In the case of vehicles, it was not even necessary to look up the acquisition date, as the description of the vehicle included the model year, which was assumed to be the acquisition year.

All vehicle retirements over the seven years between 1990 and 1996 were analyzed. Exhibit V-1 shows the cumulative service life distribution for automobiles. Exhibit V-2 shows the same for pickup trucks and Exhibit V-3 for snowmobiles.

Exhibit V-1

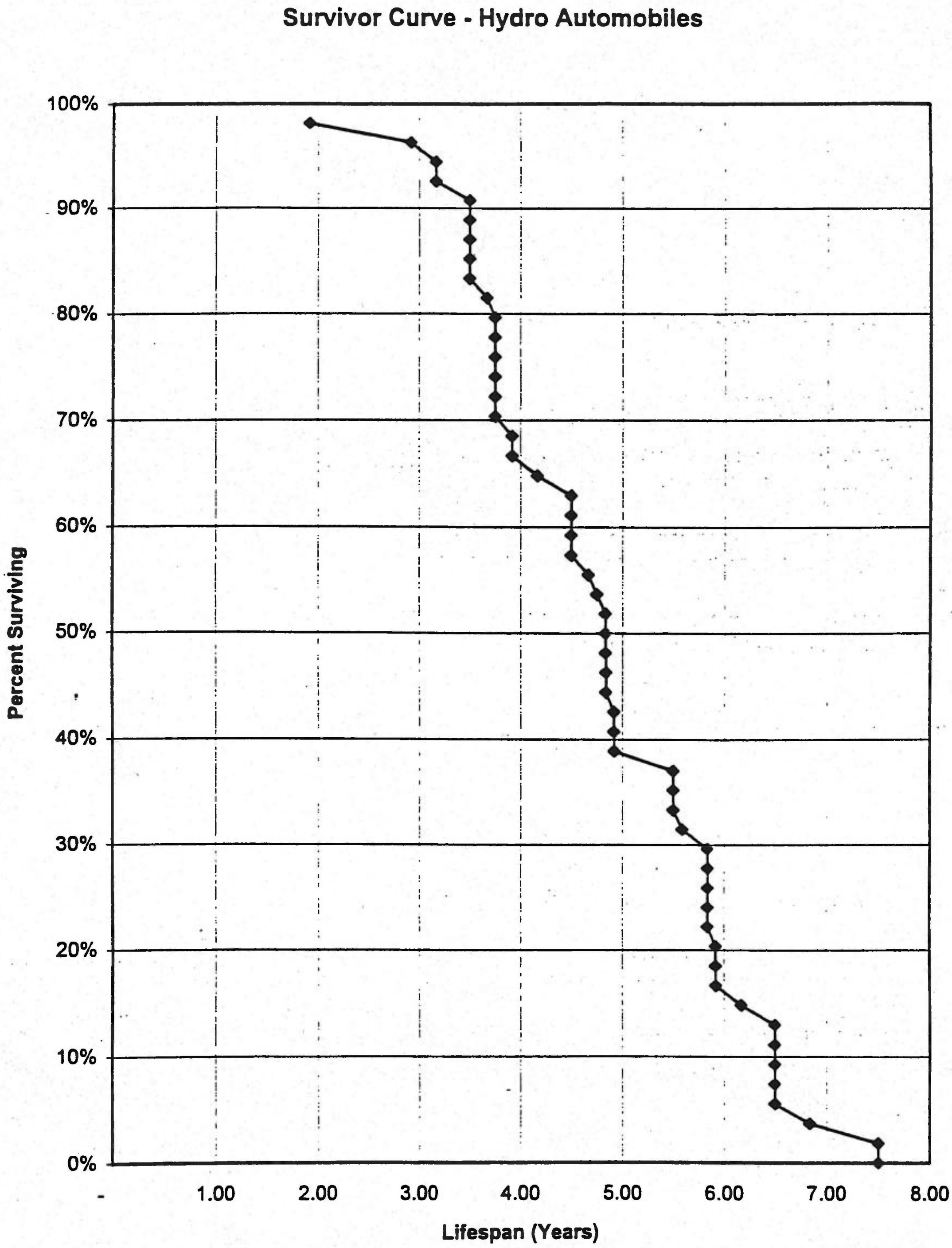

Survivor Curve - Hydro Automobiles
Percent Surviving
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
-
1.00
2.00
3.00
4.00
5.00
6.00
7.00
8.00
Lifespan (Years)

Exhibit V-2

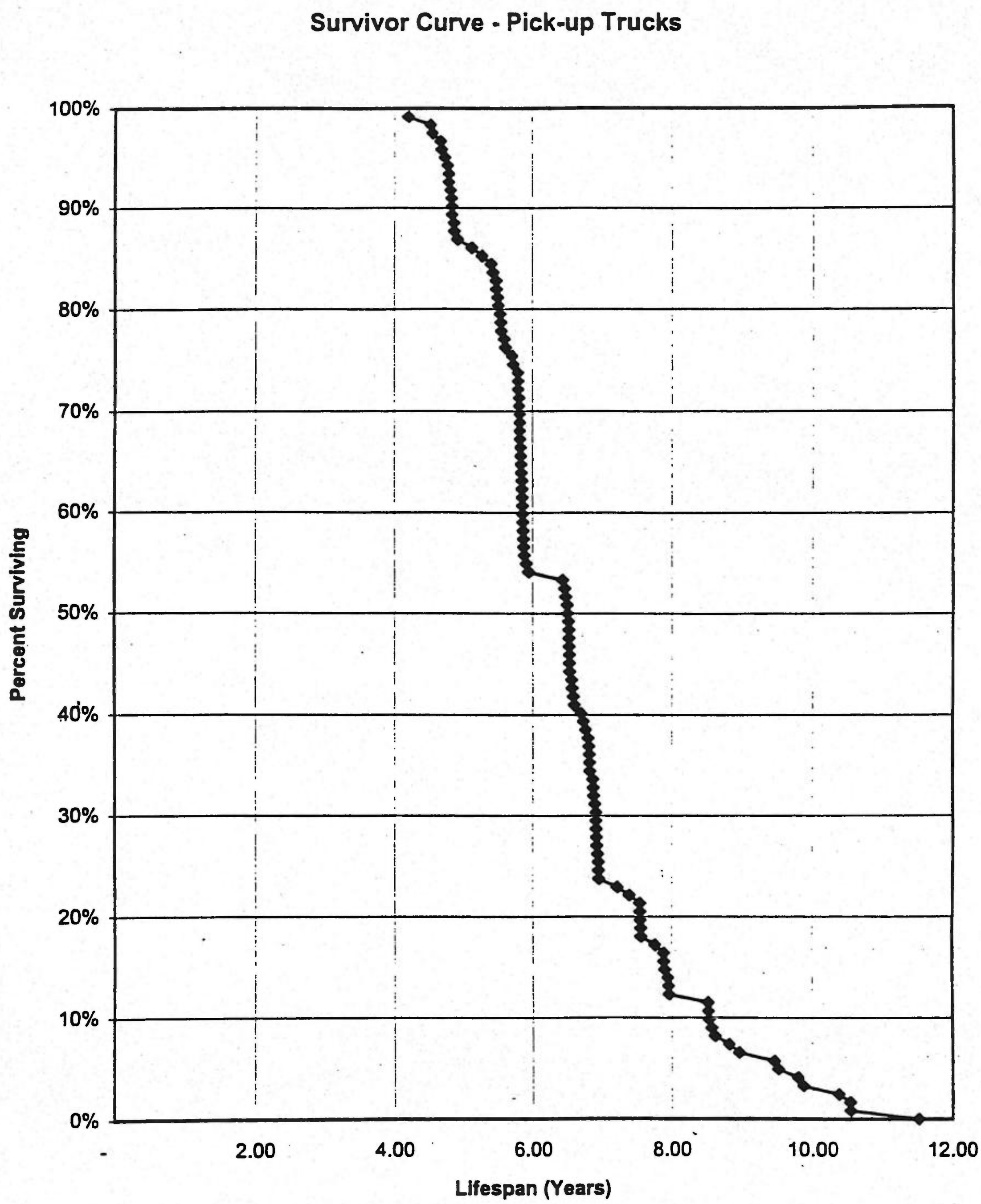
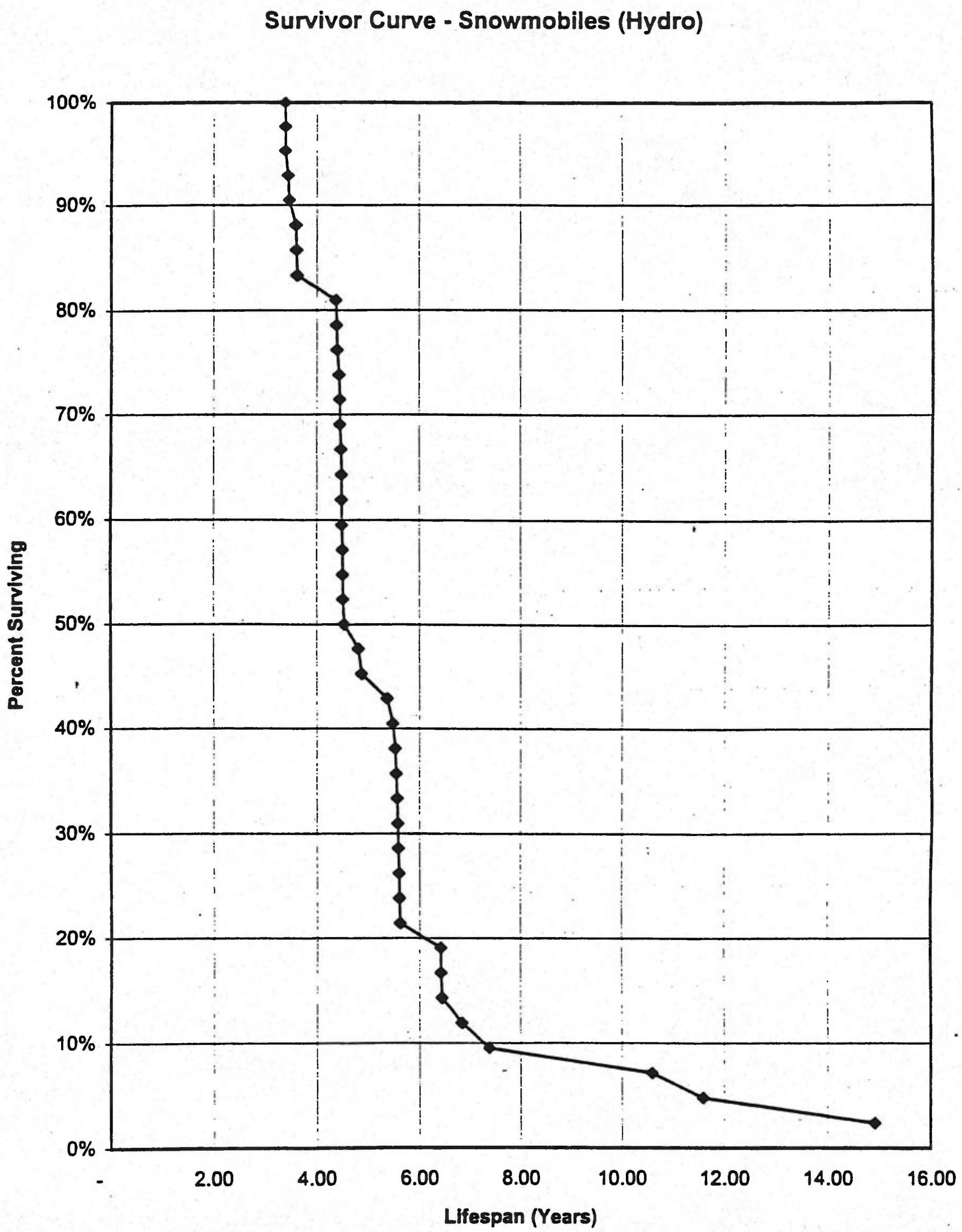

Survivor Curve - Pick-up Trucks
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent Surviving
-
2.00
4.00
6.00
8.00
10.00
12.00
Lifespan (Years)

Exhibit V-3


Survivor Curve - Snowmobiles (Hydro)
Percent Surviving
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
-
2.00
4.00
6.00
8.00
10.00
12.00
14.00
16.00
Lifespan (Years)

From the data it could be determined that the average service life of automobiles is 4.8 years. This is substantially higher than the three-year service life used by NLH for depreciation purposes.

On the basis of the findings, it is suggested that this number be increased to five years.

The corresponding number for pickup trucks was found to be 6.6 years and for snowmobiles 5.4 years. It is therefore recommended that the service lives of pick-up trucks and snowmobiles be uniformly increased to six years.

Exhibits V-4 to V-6 show the salvage (or trade-in) values for vehicles retired between the ages of 3 to 8 years. As shown in Exhibit V-4, with some exceptions, trade-in values as high as 40% were achieved for 3 to 4 year-old automobiles. This percentage drops to below 15% for cars that are 6 to 7 years old.

It was recommended in Chapter III that salvage values shall not be recognized in depreciating vehicles, as ignoring salvage and recognizing the proceeds of sale as income produces the same bottom line as recognizing salvage in the depreciation rate and offsetting the residual undepreciated balance by the trade-in value on disposal

B. Service lives of other types of equipment

Similar analysis for other types of assets with relatively short lives (up to 20 years), applied to all retirements between 1987 and 1996, produced the following average service lives:

Battery banks:	13 years
Compressors:	20 years
Radio equipment:	19 years

A similar analysis of power transformers, current transformers, and potential transformers was also attempted. However, it was found that the sample that could have been used in the analysis would have been biased, as transformers with long lives would not have been captured. The reason for that problem was the fact that NLH does not have sufficiently long history for retiring transformers that are 20 to 30 years old, and no history at all for transformers with actual service lives in excess of 30 years. As assets in service are not coded by equipment codes and, consequently, transformers in service could not be counted by vintage year and acquisition cost without a substantial amount of manual work, it was not possible to determine the percentage of all transformers in the system that were retired between 1987 and 1996, by vintage year of acquisition. This was the reason why our analysis had to focus on short-life assets. Nonetheless, it was possible to perform a limited analysis of all assets in an aggregate form, which is described below.

Exhibit V-4

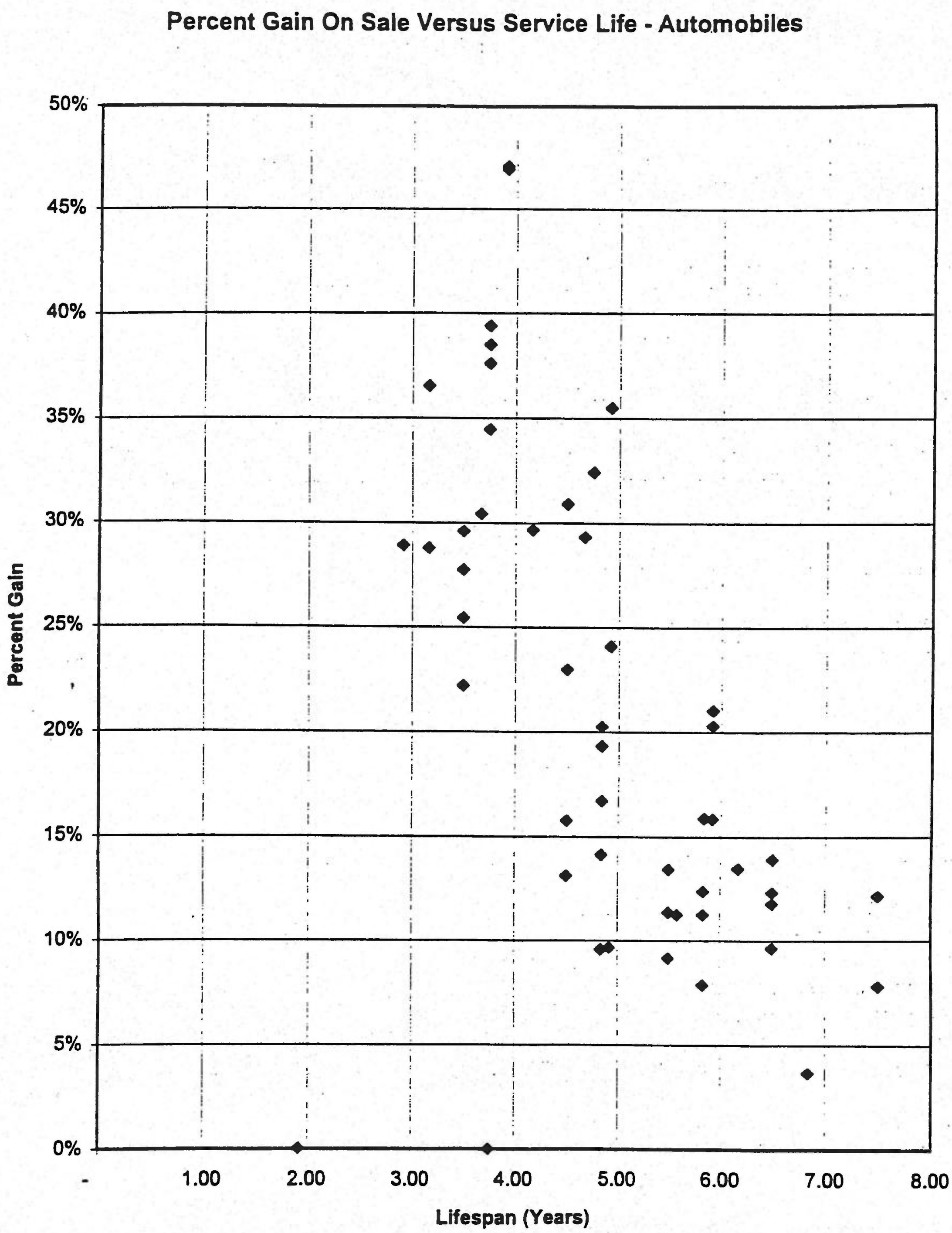

Percent Gain On Sale Versus Service Life - Automobiles
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
Percent Gain
-
1.00
2.00
3.00
4.00
5.00
6.00
7.00
8.00
Lifespan (Years)

Exhibit V-5

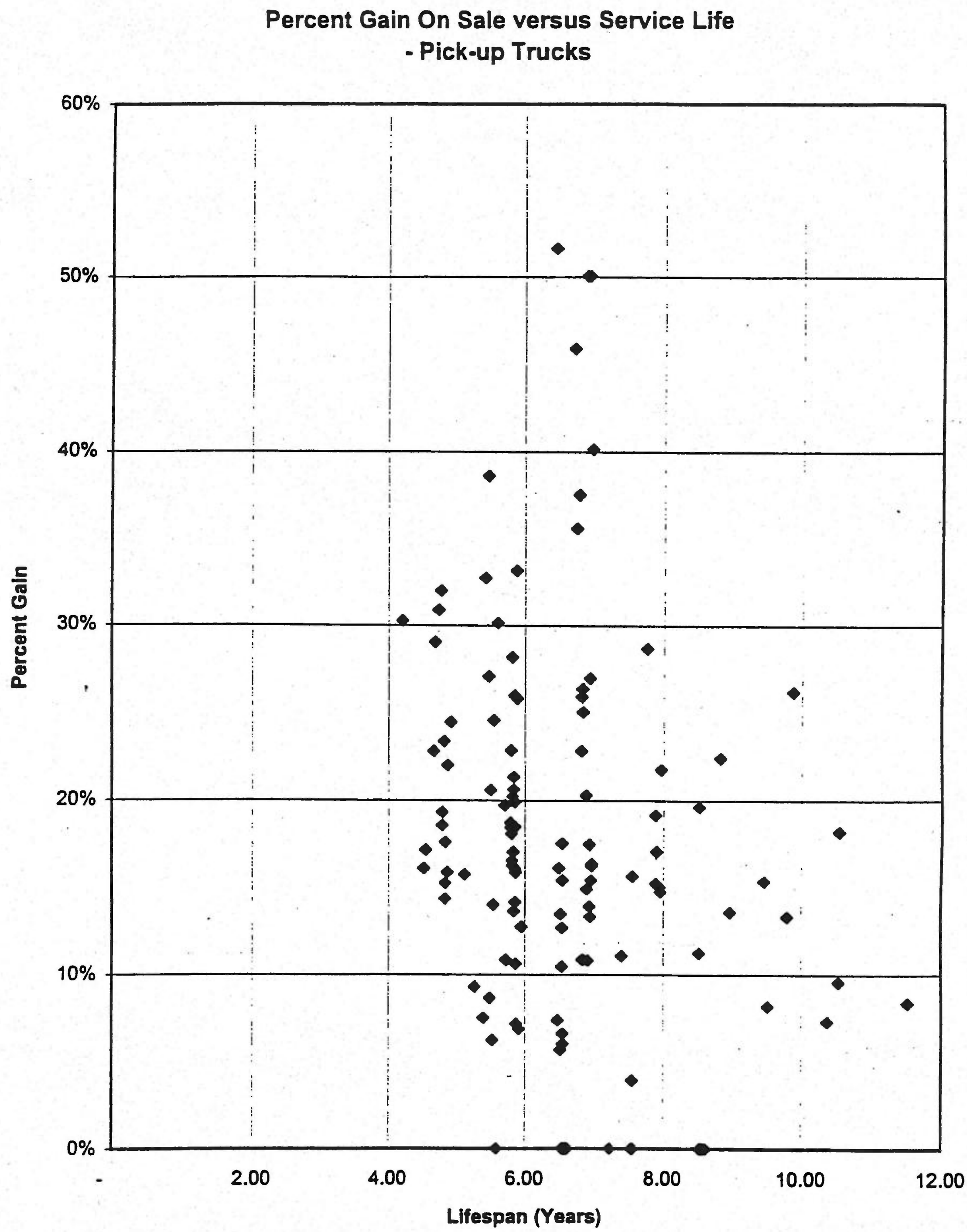
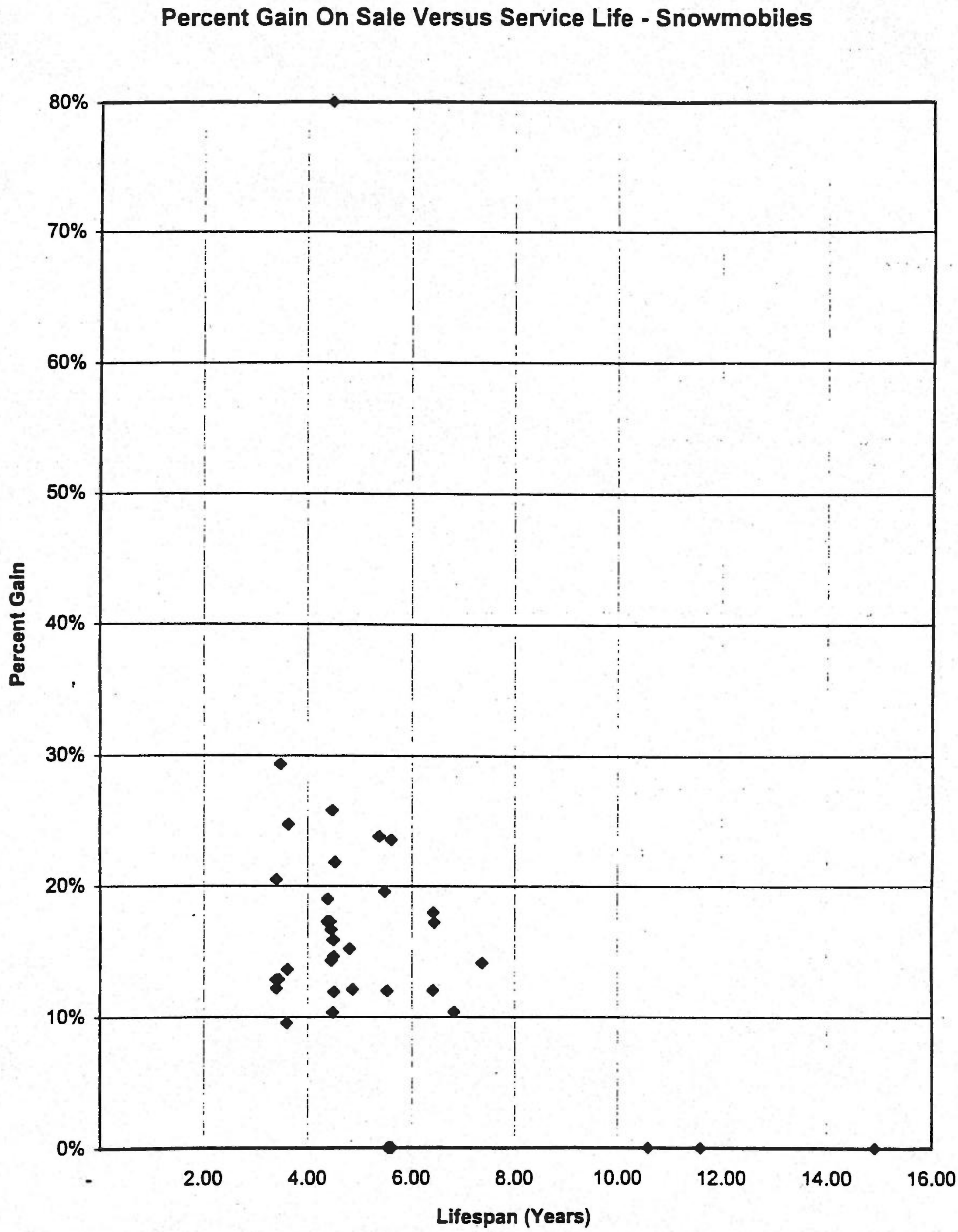

Percent Gain On Sale versus Service Life
- Pick-up Trucks
60%
50%
40%
30%
20%
10%
0%
Percent Gain
-
2.00
4.00
6.00
8.00
10.00
12.00
Lifespan (Years)

Exhibit V-6


Percent Gain On Sale Versus Service Life - Snowmobiles
Percent Gain
80%
70%
60%
50%
40%
30%
20%
10%
0%
-
2.00
4.00
6.00
8.00
10.00
12.00
14.00
16.00
Lifespan (Years)

C. Asset retirements and survivals in aggregate

It was possible to add up all the undepreciated amounts of retirements in NLH's "Hydro" system that occurred between 1987 and 1996. These were the write-offs attributable to assets not attaining their estimated service lives.

The total amount was approximately $7.56 million over the ten-year period, i.e., $756,000 per year.

Next, from the EPS system records, and the financial analysis described in Chapter VI, we identified the assets that have been fully depreciated but were still in service at the end of 1996. All of these assets were subject to straight line depreciation before they reached the end of their estimated service lives.

The total depreciation amount of these assets, in the last year of their estimated service lives, amounted to $814,000. This is the amount of depreciation that stopped at the end of the assets' estimated service life, even though these assets continued to remain in service. This is the amount that can be considered NLH's annual gain from the fact that some assets last longer than expected.

When the figure above is compared with NLH's loss attributable to premature retirements (the average annual figure of $756,000), it can be concluded that the two numbers, for all practical purposes, offset each other. This leads to the conclusion that, in aggregate, NLH's service life estimates for short and medium-life assets, other than vehicles, are appropriate.

As NLH's history is still only 30 years old, it will not be known for some time whether the service life estimates for those assets that have been attributed service lives of 30 years or more (i.e., the vast majority of NLH's assets in terms of value) are appropriate. Considering that such large assets as the Holyrood Thermal Generating Station is some 25 years old, and is approaching its estimated 30-year service life, it is quite likely that Holyrood will be operating considerably longer and, therefore, the 30-year service life attributed to this asset will be found low.

As noted later in the report, the extension of Holyrood Generating Station's service life appears to be justified. Such service life extensions may also apply to some of NLH's other generating assets. It is also noted later in the report that engineering Condition Surveys are practical approaches to determining the most appropriate service life extensions and the corresponding adjustments in depreciation rates.

D. Conclusions

NLH's service life estimates and corresponding depreciation rates were found to be appropriate, with the following exceptions:

- With respect to assets with estimated service lives in excess of 20 years, historical evidence is insufficient to conduct a definitive analysis. Nonetheless, on the basis of the observed small number of retirements of those assets, it can be stated that their actual service lives are probably longer than originally estimated. In fact, it is becoming increasingly apparent that the service lives of thermal generating plants will almost certainly be longer than estimated.

- Accordingly it is recommended that engineering Condition Surveys shall be conducted at those thermal generating plants that are approaching the end of their presently estimated service lives, with a view to possible extensions of their remaining lives and corresponding adjustments to their depreciation rates. The Holyrood generating units were identified as prime candidates for such revisions.

- An analysis of other assets with service lives up to 20 years indicated that NLH's early retirements are well in balance with those assets that are fully depreciated and still in service (late retirements). The analysis indicated that NLH's average annual write-offs attributable to early retirements are quite close to the reductions in depreciation expenses attributable to those assets that continue providing service at zero net book value. It was concluded from this finding that NLH's service life estimates for most assets with service lives of up to 20 years are appropriate, except for vehicles.

- Vehicles appear to have longer actual service lives than estimated by NLH. On the basis of KPMG's analysis, it is recommended that the service lives of passenger cars be extended from 3 to 5 years and that of snowmobiles and pick-up trucks shall be set at 6 years.

VI

Financial Projections

In order to assess the financial impacts of potentially changing NLH's depreciation methods from sinking fund to the straight line method for all assets, projections were prepared for NLH's depreciation expenses and net asset values to the year 2036. The following methodology was used:

- All of NLH's major assets, with acquisition costs in excess of $3 million were tabulated. That set of assets consisted of 101 items.

- Next, the remaining records in the EPS system were sampled. The sample was drawn in a random fashion. It was attempted to obtain the following approximate sampling rates:

  - Hydraulic generation: 30%.
  - Transmission lines and substations: 15%.
  - Thermal generation and general equipment: 10%.

  After the sample has been selected and tabulated, the percentage of the sample's total acquisition cost and total net asset value was somewhat different from the original target but the difference was not material. The actual percentages were used to expand the sample data to the totality of each service category.

- After each item in the sample was tabulated, it consisted of:

99	"major assets" in the "Hydro" system
2	"major assets" in the "Rural" system
411	other assets in the "Hydro" system
152	other assets in the "Rural" system
664	total assets in the system

  The number of assets represented in the sample was considered sufficiently large to provide a meaningful comparison between depreciation alternatives.

- Once the 1996 base year data were tabulated, the depreciation and net asset values of each asset were projected to each year of a 40-year period, ending in

2036. In carrying out the projections, most of the assets reached the end of their service lives. At that point they had to be replaced with equivalent new assets. The projections were then continued with the new assets replacing the old ones. Some assets were renewed several times.

- When an asset was retired and replaced in this sequence, its original acquisition cost was inflated to the year of replacement and the new asset was put in place at that acquisition cost. The depreciation continued according to the same pattern as the depreciation of the original asset. The price inflation of assets from their original acquisition year to 1996 was estimated from Statistics Canada price indices relating to the particular type of electrical power facility or equipment. From 1996 onward, a uniform inflation rate of 2 percent per year was assumed.

Exhibit VI-1 shows the projected total depreciation expenses and net asset values related to all of NLH's assets currently subject to sinking fund depreciation. Those numbers are shown in the first two columns of the Exhibit. The next two columns show the corresponding numbers under the assumption that the sinking fund depreciation was changed to straight line depreciation in 1997.

In implementing that change in the tabulations, it was assumed that:

- the service life of the asset to which the change was applied does not change, and

- no retroactive adjustment is made to the amount of accumulated depreciation, the straight line principle being applied only to the remaining life of the asset.

After the retirement of a particular asset that was in service in 1996, its replacement asset was also be subjected to straight line depreciation.

Exhibit VI-2 shows the differences between the two scenarios for each year. The Exhibit first shows the increase in depreciation attributable to the change. It next shows the interest that NLH would have to pay each year which would be lower under straight line depreciation, due to lower net asset values. The third data column shows the sum total of the change in depreciation and change in interest. That is the amount that will affect NLH's rate payers.

The word "interest" is used here in a broad sense, to the effect that it includes two components in addition to the coupon rate of NLH's bonds:

- A 1% premium paid by NLH to the Government of Newfoundland for guaranteeing the bonds.

- A return on equity, assumed to be higher than the bond rate.

EXHIBIT VI-1

IMPACTS OF CHANGING SINKING FUND TO STRAIGHT LINE DEPRECIATION

Assets currently under sinking fund depreciation

	SINKING FUND DEPRECIATION		STRAIGHT LINE DEPRECIATION	
	Net Assets	Depreciation	Net Assets	Depreciation
1997	975,873,529	6,172,662	955,381,380	26,484,008
1998	969,618,883	6,748,840	929,212,044	26,382,808
1999	962,262,814	7,377,758	902,544,109	26,419,590
2000	966,312,141	8,035,530	887,980,223	26,395,975
2001	957,834,336	8,307,129	861,121,236	26,445,134
2002	948,642,048	9,186,639	834,442,033	26,447,946
2003	941,298,454	10,211,095	810,690,799	26,911,883
2004	929,551,343	11,583,275	783,861,606	27,070,095
2005	925,452,206	13,551,901	759,767,634	27,068,908
2006	1,036,522,061	12,309,159	855,576,105	27,441,960
2007	1,036,680,234	12,830,724	836,768,694	29,527,072
2008	1,067,673,208	13,502,667	853,070,814	29,278,576
2009	1,120,348,586	14,264,412	889,615,785	30,048,211
2010	1,112,925,252	15,087,377	866,786,297	31,782,020
2011	1,097,017,634	16,233,773	836,109,015	32,134,366
2012	1,079,529,602	17,796,481	808,760,645	32,130,859
2013	1,090,784,146	19,430,099	808,389,771	32,283,863
2014	1,093,722,216	21,262,861	800,986,303	32,866,437
2015	1,074,962,776	22,858,952	773,183,472	33,266,558
2016	1,339,628,953	24,590,628	1,068,680,779	33,587,533
2017	1,423,071,062	26,406,771	1,141,300,793	37,380,287
2018	1,500,168,522	27,282,048	1,207,144,529	38,173,964
2019	1,720,106,556	29,467,457	1,407,521,335	39,376,045
2020	1,772,555,456	31,051,796	1,414,434,051	42,733,370
2021	1,769,201,700	32,599,659	1,398,828,645	44,333,875
2022	1,792,466,474	34,181,963	1,410,964,770	44,654,057
2023	1,915,055,846	33,362,590	1,520,876,726	44,261,817
2024	1,883,405,045	35,235,506	1,474,131,740	46,798,595
2025	1,872,181,673	38,515,443	1,450,645,367	47,206,851
2026	1,844,882,073	41,145,728	1,413,324,142	47,645,676
2027	1,852,617,368	43,502,140	1,455,629,740	47,762,384
2028	1,857,592,243	47,445,245	1,412,167,370	49,011,306
2029	1,811,648,209	51,109,873	1,364,053,997	50,035,502
2030	1,863,457,725	55,529,111	1,459,944,849	50,023,489
2031	1,855,693,986	57,036,921	1,409,511,960	50,904,720
2032	1,857,778,357	56,862,360	1,371,862,068	51,461,332
2033	1,978,210,365	60,817,179	1,490,271,739	51,986,759
2034	2,005,265,558	64,334,354	1,439,123,625	53,011,715
2035	2,372,504,018	64,763,930	1,797,826,075	53,205,740
2036	2,376,652,843	66,245,185	1,778,441,878	55,000,361

EXHIBIT VI-2

IMPACT OF CHANGE IN DEPRECIATION METHODS

Increase in expenses resulting from change

	Difference in Depreciaton	Difference in Interest	Total Difference	Difference per Household / Month (1997 $)
1997	20,311,346	-1,844,293	18,467,052	$7.08
1998	19,633,969	-3,636,616	15,997,353	$6.01
1999	19,041,832	-5,374,683	13,667,149	$5.04
2000	18,360,445	-7,049,873	11,310,573	$4.09
2001	18,138,005	-8,704,179	9,433,826	$3.34
2002	17,261,307	-10,278,001	6,983,305	$2.42
2003	16,700,788	-11,754,689	4,946,099	$1.68
2004	15,486,820	-13,112,076	2,374,744	$0.79
2005	13,517,007	-14,911,611	-1,394,604	-$0.46
2006	15,132,801	-16,285,136	-1,152,335	-$0.37
2007	16,696,348	-17,992,039	-1,295,691	-$0.41
2008	15,775,908	-19,314,216	-3,538,307	-$1.09
2009	15,783,799	-20,765,952	-4,982,153	-$1.51
2010	16,694,642	-22,152,506	-5,457,864	-$1.62
2011	15,900,594	-23,481,776	-7,581,182	-$2.20
2012	14,334,378	-24,369,206	-10,034,828	-$2.86
2013	12,853,764	-25,415,494	-12,561,730	-$3.51
2014	11,603,575	-26,346,232	-14,742,657	-$4.04
2015	10,407,606	-27,160,137	-16,752,531	-$4.50
2016	8,996,905	-24,385,336	-15,388,431	-$4.05
2017	10,973,515	-25,359,324	-14,385,809	-$3.71
2018	10,891,916	-26,372,159	-15,480,243	-$3.92
2019	9,908,588	-28,132,670	-18,224,082	-$4.52
2020	11,681,574	-32,230,926	-20,549,352	-$5.00
2021	11,734,216	-33,333,575	-21,599,359	-$5.15
2022	10,472,093	-34,335,153	-23,863,060	-$5.58
2023	10,899,227	-35,476,121	-24,576,894	-$5.63
2024	11,563,089	-36,834,597	-25,271,508	-$5.68
2025	8,691,408	-37,938,268	-29,246,860	-$6.44
2026	6,499,948	-38,840,214	-32,340,265	-$6.98
2027	4,260,244	-35,728,887	-31,468,643	-$6.66
2028	1,566,061	-40,088,239	-38,522,178	-$7.99
2029	-1,074,371	-40,283,479	-41,357,850	-$8.41
2030	-5,505,623	-36,316,159	-41,821,781	-$8.34
2031	-6,132,200	-40,156,382	-46,288,583	-$9.05
2032	-5,401,028	-43,732,466	-49,133,494	-$9.42
2033	-8,830,421	-43,914,476	-52,744,897	-$9.91
2034	-11,322,639	-50,952,774	-62,275,413	-$11.47
2035	-11,558,189	-51,721,015	-63,279,204	-$11.43
2036	-11,244,824	-53,838,987	-65,083,811	-$11.53

Including the components above, a combined cost of capital of 9 percent was assumed. This number takes into consideration the current long term bond yield, or "interest", of approximately 6.5%, and allows for some increase in that rate in future years.

For simplicity's sake, no growth was assumed in NLH's plant, and annual capital expenditures were confined to the replacement of retired assets. This assumption may understate the true future. To offset the impact of that simplification, no growth was assumed in generation, peak load, or the number of customers either. We believe that if growth was considered in both the capital plant and electricity production/consumption, the results of the analysis and the conclusions drawn from them would not change materially.

The last column of Exhibit VI-2 shows the impact of the changes from sinking fund to straight line depreciation on the average residential customer. It is based on the assumption that every $ 1 million increase in revenue requirements will cause a $4.60 per year increase in residential and commercial electricity rates (in 1996 dollars). This amount was obtained in the following manner:

- It was determined that NLH's revenue from Island services was $266.1 million in 1996.
- Of this amount, $218.6 million, or 82 percent, was ultimately derived from the Island's residential and commercial customers (through the distributing utility) and the Island's rural customers (while the remainder was derived by NLH from the Island's industrial power users).
- There were 178,000 dwellings on the Island in 1996 (Census).
- In order to generate 82 percent of a $1 million increase in revenues, each dwelling would have to pay $820,000/178,000 a year. This amounts to approximately $4.60 per year, including amounts passed on to the public by commercial electricity users in the form of price increases.

The monthly contribution of households (dwellings) to NLH's increased revenue requirement, shown in Exhibit VI-2, was calculated by multiplying the required increase, expressed in million dollars, by $4.60, and dividing the result by 12.

Conclusions

Switching the depreciation method to straight line for all assets would have cost NLH's residential customers about $7.00 per month in that year. This amount would decline below zero after 8 years, and would change to negative impacts of about $7.00 (in 1997 dollars) around approximately 2026.

Because of the time factor, Newfoundland residents would be negatively affected by a change to straight line depreciation.

VII

The Engineering Review

A. Methodology

The engineering firm of Acres International Limited performed an engineering appraisal of selected NLH assets and reviewed the operating and maintenance records of these assets. This process enabled an opinion to be rendered on the appropriateness of the service lives being used by NLH and respond to the question whether those service lives were adequately supported by NLH's operation and maintenance procedures.

A similar study was conducted in 1986 for NLH by KPMG and Acres. This earlier study report was part of the documentation reviewed for the current engagement.

For the purpose of this study, it was clearly not practical to make an appraisal of all NLH's assets. Accordingly, it was necessary to select a number of assets to form a sample that could be considered to reasonably reflect the range, type and age of the total assets. The Asset Sample comprised the facilities listed below:

- Bay d'Espoir Hydro Generating station.
- Cat Arm Generating Station.
- Holyrood Thermal Station.
- Hardwoods Gas Turbine Plant.
- Stoney Brook and Sunnyside Substations.
- Transmission lines in general (sampled in the form of spot checks).

The 1986 depreciation study recommended that NLH consider adjusting the service lives selected for a number of asset types. NLH implemented these recommendations.

Further changes were made by NLH to assigned service lives for assets not encompassed by the 1986 study. Specifically, a portion of the 5 MW Roddickton Wood Fired Generating Plant had been changed in 1996 from 30 to 3 years due to obsolescence. The service lives of large tracked and wheeled vehicles were changed in 1991 from 3 to 5 or 10 years, depending on type, and in 1991 the service lives of computer equipment were changed from 10 to 5 years.

The methodology applied by Acres to the review included the following steps:

- Since, for both thermal and hydro generation, NLH computes and provides various statistical operating data to the CEA Annual Equipment Reliability Information System, it was possible to compare NLH's performance with other Canadian utilities. The CEA survey data were among the documents reviewed.

- Senior staff and operating personnel were interviewed and O&M procedures reviewed.

- A partial copy of the NLH asset register, which was provided, gave the asset breakdown and service lives selected by NLH for each of the assets included in the Asset Sample.

- Each of the selected facilities included in the Asset Sample was visited to gain an appreciation of the current status of the facility and the quality of the maintenance.

- A review of the design and construction of the various facilities was not undertaken, other than for a review of the design parameters used for transmission lines. Each of the companies involved with the execution of the design and construction was fully qualified for the work undertaken and the quality of the design or construction was not considered to be in doubt.

B. Engineering appraisal

The following subsections provide detail on the interviews conducted, the documentation reviewed and the site inspections.

1. Hydro facilities

For the purpose of this study, hydro generation facilities were considered as comprising two components, namely:

- Civil structures, in particular water retaining or conveying dams, canals and concrete structures.

- Generation facilities, including all electrical and mechanical components.

a) Civil structures

Bay d' Espoir and Cat Arm hydro developments include dams classified in "High" and "Low" consequence categories, following the recommendations of the Canadian Dam Safety Association guidelines. The dams are generally earth and rockfill structures that require monitoring. The need for some occasional remedial work can be anticipated. The power canals are either excavations in rock, or formed by one or more dykes. The spillways and control structures are reinforced concrete with vertical lift gates, operated by wire rope hoists or screw jacks. Proper maintenance of such structures requires informed, responsible management.

Within NLH, the Generation Engineering and Telecontrol Group has responsibility for the maintenance of the civil structures. NLH have developed and implemented a proactive monitoring program that includes

- Holding an in-house workshop on dam surveillance to train the operational personnel (almost exclusively electrical or mechanical).

- Weekly inspection of structures by field operational personnel, other than the remote structures which are inspected biweekly.

- Monthly inspections of the crests and toes of the complete dam system. The inspection reports are summarized, reviewed and actioned when necessary, by the engineering staff.

- Annual inspections by the Dyke Board. This is a group of eminent engineers commissioned by NLH to inspect and report on the conditions of the structures and make recommendation on any aspect they suggest requires attention.

The Dyke Board recommendations are considered in house and either adopted, or alternative measures are taken and reported to the Dyke Board.

During the site inspections, a positive impression was gained both from interviews with a number of the operational personnel and from the well maintained road access and tidy nature of the generally remote sites. There appears to be good communication between engineering staff responsible for the maintenance of the structures and the field staff making daily observations.

The comprehensive nature of NLH's monitoring and maintenance program demonstrates a commitment and responsible owner attitude towards safely and appropriately maintaining the structures.

NLH has generally selected a 100 year service life for dams and 75 year life for major concrete structures. These numbers are a financial expression of a 'long life', not necessarily the economic or expected life. These major structures are likely to have practical and generally useful economic service lives in excess of those selected. Dams, in particular, are rarely decommissioned or removed.

The service lives selected by NLH for the structures are reasonable and agree with normal industry practice. The operation and maintenance program developed and followed by NLH is considered to ensure that those service life spans are met and likely exceeded.

b) Hydro generation facilities

In 1992, the centre of operations was moved from Bay d' Espoir to the St. John's Energy Control Centre. From this centre hydro generation is monitored and controlled. (Thermal generation is also monitored here, but the control is still local at the Holyrood station.) This all requires a sophisticated computerized network that is maintained by NLH engineering staff. This facility appears to be functioning satisfactorily.

CEA's 1996 Equipment Reliability Information System data were reviewed. Such a review allows a comparison of NLH's performance with the average performance of other Canadian utilities. This is achieved by using a series of 'generation unit availability' and 'scheduled and forced outage' parameters, used to measure a utility's performance. NLH has a fairly small number of generation units (12 in total) and any outage has a marked effect on the calculation of 'outage rate'. Also, since a number of NLH's stations are unmanned, any forced outage that requires manual checking before restarting the unit may last longer than would be the case with a manned facility. This being the case, it can be reasonably concluded from the CEA's data, that the performance of NLH compares favorably with other Canadian utilities.

NLH's Preventative Maintenance Plan combines planned routine preventative measures and corrective maintenance in the following manner:

- NLH has a series of Preventative Maintenance (PM) plans that detail the routine maintenance to be performed at specific intervals at scheduled times; check sheets are included, which record the work performed and the data collected. Examples of completed check sheets were scanned.

- Corrective Maintenance corrects specific problems identified during service.

The 5-year Preventative Maintenance Plan is updated annually, adding any additional corrective needs identified, or rescheduling any that were not completed. Scanning this document shows it to be a comprehensive plan that takes note of routine and correction-driven matters, assigning priority as needed, and being sufficiently flexible to accommodate forced outage work.

Some of the work undertaken is driven by operational reliability and other by economic benefit considerations. For example:

- The current program to replace the exciters at Bay d' Espoir is the result of a study initiated by NLH because of high fault incident levels with the original exciters, which were reaching the end of their economic (and selected) service life. Replacing the exciters has restored the reliability of the units.

- Initially, at Bay d' Espoir, there were a number of problems with corrosion and cavitation damage to the runners. These were gradually overcome with advances in the technology of weld overlays. In 1994, a turbine manufacturer proposed changes to the runners and hydraulic passages to improve the performance of the units. Some modifications were made and economic benefit has been realized.

A walk-through of the generating stations revealed them to be clean and tidy, well run and well maintained. Five stations were visited. Two were part of the Asset Sample. Three others were visited as examples of an unmanned facility (Upper Salmon), of small stations (Sops Arm and Venams Bight), and a station where some maintenance work was in progress (Hinds Lake).

- Upper Salmon consists of a single 84 MW unit powerhouse, commissioned in 1983. This station is remotely operated and has no full time operator; the area senior supervisor visits the plant three times a week and conducts visual inspections of the structures as well as the generation facility.

- Bay d' Espoir, a 7 unit facility with a total output of 604 MW, was commissioned between 1967 and 1978. This station is remotely operated, but has two operators in full time attendance. Bay d' Espoir is the maintenance center for all NLH hydro generation stations.

- Hinds Lake consists of a single 75 MW unit powerhouse, commissioned in 1980. At the time of the visit a maintenance crew had been dispatched from Bay d' Espoir and PM6 work was close to completion. A "PM6" is the annual maintenance procedure that includes inspection of the dewatered unit.

- Sops Arm and Venams Bight, (0.6 and 0.4 MW) are single unit facilities, commissioned in 1956 and purchased by NLH in 1968 from Baie Verte Mines. A single operator maintains both facilities; there is only local control. Both stations are well maintained and run continuously.

In addition to the service lives listed in Chapter IV, NLH uses the service lives listed below for remaining major hydro generation components.

Asset Type	NLH Selected Service Life	Comment
Pumps	25 yr	None
Compressed Air System	25 yr	None
Surge Tanks	50 yr	Extensive repair work completed in 1996 at Bay d' Espoir after 30 years of service.
Turbines & Governors	50 yr	Extensive remedial work performed in the 1980's after 20+ years and refurbishment, enhancing performance, in the 1990's.
Gates, Stoplogs & Trashracks	50 yr	None
Powerhouse Crane	75 yr	None
Exciter	25 yr	Bay d' Espoir exciters currently being replaced after 28 years of service.

These service lives are in line with general practice in the electricity sector in Canada and are adequately supported by NLH's operation and maintenance procedures.

2. Thermal generation

a) Holyrood Generating Station

The Holyrood Generating Station comprises three residual oil-fired boiler and steam turbine generator units plus station auxiliaries for cooling, fuel storage, water treatment, etc. Units 1 and 2 are rated at 175 MW each, and were commissioned in late 1969 and early 1970 respectively. Unit 3, rated at 150 MW, was commissioned in 1979. Units 1 and 2 were upgraded to 175 MW in 1988/89 from an initial rating of 150 MW. A 12-MW light oil-fired gas turbine generator provides black start power to the steam plant in event of the loss of the network. Holyrood is controlled from a central control room and provides mid-range and peaking power from September to May. Unit dispatch is by voice link from the Energy Control Centre in St. John's. In the winter peak period, all three units are usually in operation. Annual operating hours have gradually increased with system load increases.

The plant was visited on September 30 and October 2, 1997, with the following objectives

- Review operating and maintenance history and procedures.
- Inspect the condition of the plant.

The Holyrood plant currently operates at a capacity factor of about 50 percent providing power to the grid, as noted, only during the colder months of the year. With no summer peaking requirement, the plant does not operate in the summer months during which time scheduled maintenance is carried out. NLH have recently entered into the following partnering agreements

- Boiler Plant: ABB
- Turbine Plant: GE
- Pumps: Byron Jackson.

Under these agreements, the partner contractors provide major maintenance labour, monitoring technical assistance, and share in the financial risk on overhaul costs. The principal objective is to reduce forced outage time and increase plant availability. The on-site technical assistance should have a significant beneficial effect on the life of the facility.

Turbine overhauls have been averaging one every four years. Hydro is trying to extend this to every five years, which would be normal for this type of plant. Turbine valve overhauls are also undertaken every 2 to 3 years or mid-way between the major overhauls.

When comparing Holyrood's operation with other fossil-fired units in Canada over the 5-year period 1991 through 1996, Units 1 and 3 are generally superior in the critical reliability measurement of forced outage time. Unit 2 exhibits forced outages more frequently than the statistical average, although when adjusted for unit deratings the difference is minimal. Unit 2's higher forced outages appear to be the result of seven major outages to turbine generator equipment, which, however, do not indicate any serious inherent problems with this unit. Scheduled maintenance is carried out through the summer months on a non-urgent basis, which results in distorted statistical data on unit availability.

Hydro's maintenance program over the last 10 years has been based on the Reliability Centered Maintenance approach which is used in a number of North American industries to concentrate resources on reliability improvement functions.

The adoption of the partnering approach with major overhaul contractors can be expected to result in increased equipment reliability and unit availability and an extended life of the plant.

The general condition of the plant appears to be normal, exhibiting expected levels of equipment appearance and replacement of subsystems (e.g., water treatment). Unit thermal performance is satisfactory with each able to meet Maximum Continuous Rating (MCR) on a sustainable basis, except for No. 3 unit, where a boiler backwall slagging and reheat spray problem has limited maximum output to 145 MW from the original 150 MW capability. Hydro has been trying to correct the problem using different measures, so far unsuccessfully.

NLH assigned a 30-year service life to the Holyrood Generating Station, with 4 years remaining for Units 1 and 2, and 12 years for Unit 3.

As it is quite likely that these units will be able to remain in service considerably longer, it would be useful for NLH to conduct a Condition Survey at Holyrood, followed by a possible extension of service lives for all units.

Replacement equipment and systems have generally been allocated service lives consistent with the unit service life expiry date. The 30-year service life used is consistent with the following:

- the service life criteria in use in the power supply industry for this technology,
- the operating and maintenance history of the generating units,
- the planned operation of the facility,
- the present general condition of the units.

b) Hardwoods Gas Turbine Station

The Hardwoods Gas Turbine Station comprises a 50 MW electric generator driven at either end by a Rolls Royce Olympus C gas generator and a Curtis Wright power turbine, including station auxiliaries for cooling, fuel storage, transformation of power, etc. The plant was commissioned in 1977 and burns light distillate oil for emergency and peaking duty. The plant can be black started from the system Energy Control Centre in St. John's. Because of high operating cost, this plant is only dispatched for emergency conditions (e.g., transmission line outages in ice storms), and therefore has accumulated relatively few operating hours for generation. However, the plant operates also as a synchronous condenser and has accumulated significant running hours in this mode.

The station was inspected on October 1, 1997, with the following objectives:

- Review operating and maintenance history and procedures.
- Inspect the condition of the plant.

Since the critical plant component is the gas turbine (gas generator), some assessment of the effect on life cycle of peaking time and number of starts is necessary. The usual industry rules of thumb are:

- 1 hour at peak is the equivalent of 6 fired hours,
- 1 start is the equivalent of 20 fired hours.

While the 20:1 ratio criterion for equivalent fired hours per start may not apply to an aeroderivative gas turbine, there is a significant effect on service life expectancy and maintenance costs associated with the high number of starts. While 100,000 running hours has been the usual design target, this would mean that, in spite of the low operating hours of both gas turbines, they may still have used up about half of their normal life expectancy.

Significant events in the operating and maintenance history of the Hardwoods plant are as follows:

1979	Power turbine blade damage due to loose object passing through
1984 and 1995	Alternator end windings replaced
1984	Exciter failure
1988	Power turbine casing replaced (design fault)
1989	Both exhaust stacks replaced due to corrosion
1992	Bearing leak. Gas generator sent to overhaul facility in UK for major stripdown/refurbishment
1997	Control system revamp.

According to the CEA's Equipment Reliability Information System, the Hardwoods station had higher than average forced outage rates for the period 1991 through 1996, particularly when compared to turbines in the same annual operating range as Hardwoods. However, the principal contributing factor to the inferior results was the 1992 outage that necessitated the gas generator being sent to the UK for repairing the bearing leak.

Hardwoods is maintained by personnel from the regional maintenance centre at Whitbourne which is a 45 minute drive away.

The general condition of the plant is normal, with no visible leaks, cracks or other deterioration, except for some surface rust on the roof section inside the synchronous clutch compartment. The plant looks well protected and maintained. The 'A' end gas turbine has a shortfall reaching its full rated output of about 2 MW. The problem may be in current control or governing system. Hydro is presently adding a Distributed Control System (DCS) and hopes to identify and correct the capacity deficit with the new system. The 'B' end gas turbine is able to meet and sustain MCR.

The service life being used by Hydro for the main equipment is 25 years, which means the plant will reach the end of its service life in 5 years time. A 25-year service life for a gas turbine plant of this type is probably high compared to what is currently being used in the industry. Traditionally, gas turbines have been allocated service lives of 15 to 20 years.

Nonetheless, based on its maintenance history, planned operational duty and general conditions of the facility, there appears to be little doubt that this plant will meet its current service life target (it has already reached 20 years).

It can be anticipated that the useful economic life of the Holyrood units, the Hardwoods plant, as well as that of the Holyrood units (noted earlier), and most likely the Stephenville plant (which was not inspected as part of this study) will extend, possibly by a considerable margin, beyond their selected service lives. To estimate the remaining economic service life of these plants it would be necessary to perform a detailed Condition Survey of the equipment, together with a detailed review of their service histories and maintenance records. Conducting a Condition Survey was outside the scope of this study.

3. Substations and Transmission Lines

NLH maintenance and design practices were discussed with NLH staff on September 30 and October 1, 1997. As a result of these discussions, it was found that the NLH substation maintenance practices and their frequencies of maintenance conformed to the standards generally observed at other Canadian utilities. One departure from standard utility design practice was found in NLH's practices applied to the design of protections for transmission lines. NLH does not, at present, use duplicate primary distance protection on 230 kV lines. NLH has a program in place to rectify this departure from present standard utility design practice; thus, this issue is not of major concern. In any case, duplicate primary protection of major lines is only required in most Canadian utilities because of their interconnections with American power pools. Being not so encumbered, NLH's need for duplicate primary protection may thus be questionable.

It was noted that the original design parameters of many of the NLH lines allowed for ½ inch of ice accumulation and a wind pressure of 8 lbs. per sq ft of exposed area of conductor, including ice. These design parameters were typical of those used by other Canadian electric power utilities at the time of the design. During the last few decades there have been several instances of severe icing (caused by freezing rain) on the Island, which have caused failure of lines designed to the original design standards. All new lines built since the mid 1970's have been designed to allow higher levels of ice accumulation. Lines constructed before that time in the areas most exposed to icing, such as the lines on the Avalon Peninsula and the Isthmus, have been reinforced to allow for the experienced greater levels of ice loading. Discussions regarding the inspection and maintenance practices used for the NLH lines revealed that they conformed to standard practices used by other Canadian and North American utilities.

Two substations, Stoney Brook and Sunnyside, were inspected on October 1, 1997. Other substations, Hardwoods and Stephenville, had been inspected by Acres personnel in the summer of 1995 for a different requirement. Also, a number of transmission lines were inspected in a general way around the stations and by observing them where they crossed roads and at other easily accessible places. Acres is familiar with many of the NLH lines, having been present during the construction of some, and the repair of others, after the 1970 ice storm. Thus, it is possible to confirm that NLH's line construction practices are acceptable. The lines observed in 1997 seem to be in good repair, given their 30-year age.

NLH treats substations as a single asset type with a selected (composite) service life of 40 years. As part of this review, a composite service life was developed for Stoney Brook and Sunnyside using Ontario Hydro, the US Bureau of Reclamation and NLH service lives for the individual components that make up a substation. This composite service life calculation, shown in Exhibit VII-1, appears to support the composite service life of 40 years selected by NLH. It should be noted, however, that treating substations as a single asset, with a single service life, implies a substantial degree of approximation. As shown in the table, substations are composites of 15 or more different components which have expected service lives ranging from 15 to 60 years. Nonetheless, as also noted elsewhere in this report, the aggregate impact of the single service life assumption is not likely to be materially different from that of a disaggregated approach.

The 40-year service lives used by NLH for wood pole lines and 50 years for steel tower lines seem entirely justified when compared to the life times, for example, by Ontario Hydro, other Canadian utilities, and the US Bureau of Reclamation. In fact, given the improved strength ratings of the NLH structures to resist severe weather conditions, it is entirely likely that the lines will last significantly longer than their assigned service lives of 40 and 50 years.

C. Conclusions

All aspects of the engineering appraisal of the Asset Sample supports the view that NLH's fiscal policy regarding asset depreciation reasonably reflects the actual asset retirements likely to be experienced. In particular, the service lives selected by NLH for the purpose of asset depreciation reflect expected service lives and generally agree with those adopted by other utilities. Appropriate operation and maintenance procedures and retirement and replacements practices are required if full service life expectancy is to be realized. In this respect, NLH's preventative maintenance planning and execution were found satisfactory and fully supportive of the selected service lives. NLH's operational record compares favourably with that of other utilities, lending further support to the competency of NLH's asset management.

As noted, the make-up of the Asset Sample was developed in order to reasonably reflect the majority of NLH's assets in terms of size, type, service conditions and age. It can be reasonably suggested, that with the remainder of NLH's assets, not properly represented by the Asset Sample, NLH exercised the same degree of prudence in selecting service lives and effort for maintaining the equipment. Accordingly, NLH's total policy with regard to asset management can be considered satisfactory.

With respect to service lives it was noted earlier in the report, and confirmed by the Engineering Study, that the present service life estimates of some of NLH's thermal generating plants appear to be too low. Accordingly, it is recommended that appropriate Condition Surveys be conducted for the Holyrood generating station, as well as for the

Exhibit VII-1

Development of Composite Service Life for Substation Asset Type

		Ontario Hydro Data		US BR Data	
	Orig Cost $	Service Life years	Ann Dep Amount $	Service Life years	Ann Dep Amount $
Account Description					
Land Improvements	274229	60	4570	50	5485
Buildings	68871	50	1377	50	1377
Foundations	169674	30	5656	50	3393
Ducts and Trenches	75775	50	1516	50	1516
Structures	385709	50	7714	50	7714
Security Fencing	45780	50	916	50	916
Transformers	1623735	45	36083	40	40593
HV Switching	1735697	50	34714	40	43392
Circuit Breakers	792928	40	19823	35	22655
CM&R Panels	770971	26	29653	35	22028
Station Serv. incl Chrgrs	25808	30	860	20	1290
Control Cables & Conds	170265	31	5492	35	4865
Grounding	40292	50	806	50	806
Batteries	35297	15	2353	35	1008
Services, incl water	15727	50	315	50	315
Total Original Cost	6230758				
Annual Depreciation Amount			151848		157353
Composite Service Life			41.0		39.6

Hardwood and Stephenville gas turbine stations, with a view to extending their service life estimates.

VIII

Approaches to Grouped Depreciation Procedures

In this chapter and Appendix B, we provide a summary of the various procedures used by Canadian electric power utilities to calculate depreciation expenses for groups of assets rather than individual assets.

The purpose of group depreciation procedures is administrative simplicity, as these procedures make it unnecessary to track the service life of every individual piece of equipment within large classes of similar assets. Grouping significantly reduces the number of records that have to be continually updated within the property accounting system.

The most commonly used procedures, listed below in the order of increasing refinement and data requirements, are:

- the Average Life Group (or Broad Group) procedure,
- the Vintage Life Group procedure,
- the Equal Life Group procedure,

These procedures are described in some detail in Appendix B.

A. Group depreciation practices of Canadian electric power utilities

Exhibit VIII-1 summarizes the practices of Canadian electric power utilities. The Exhibit shows, for example, that two utilities, Manitoba Hydro and Alberta Power, use Equal Life Group depreciation procedures for all of their assets. The Exhibit provides similar information for all the other utilities.

As noted earlier, among the surveyed utilities, NLH is unique in that it does not use any form of group depreciation. Most other utilities use one form, or several forms, of group depreciation for at least some of their assets. In particular, Equal Life Group depreciation appears to be the most widely used procedure.

Exhibit VIII - 1
Basis for calculation of depreciation rates

	Individual Asset	Average Life (Group Plan or Broad Group)	Vintage Group	Equal Life Group	Other
NS Power				All asset categories. Iowa curve method for transmission, distribution and general property. Generation assets by own experience.	
NB Power Corp.	Most assets.		Distribution assets by vintage year.		
Hydro-Quebec	Major fixed assets: reservoirs, dams turbines, buildings.	All other assets, including equipment, poles, office furniture.			
Ontario Hydro	- Nuclear, fossil and hydraulic generation facilities. - Heavy water production facilities.	- Retail system facilities. - Communication and system control facilities.	- Transmission system facilities. - Distribution system facilities. - Admin. & service facilities	- Major components within fossil & hydroelectric generating stations. - Transformers & transmission stations. - According to Iowa curves & own experience.	Group/ Property: within a specific property, similar assets are grouped together.
Manitoba Hydro				- All asset categories. - According to Iowa curves.	
Sask. Power	- Power plants (all equipment at common rate). - Buildings.			- All other assets. - According to Iowa curves and own experience.	
Alberta Power Corp.				- All asset categories. - According to Iowa curves & own experience.	
Transalta Utilities	Equipment in each hydraulic plant at common rate. Everything else by asset category.	Computer H/W & S/W, and office furniture & equipment.		Includes: transmission, sub-stations, telecontrol, distribution system tools & instruments, vehicles, and machinery.	
BC Hydro	Limited quantity and/or high value assets; e.g., transformers, circuit breakers & vehicles.		Low to medium value & medium to high quantity assets ("*quantitative & mass*" assets); e.g., switches, transmission lines, equipment & poles.		

B. Should Newfoundland and Labrador Hydro consider using group depreciation procedures?

The depreciation procedures of the Canadian utilities listed in Exhibit VIII-1 are all used in conjunction with the straight line depreciation method. They relate to asset groups, in which the broad characteristics of equipment are functionally similar, even though they may differ in technical detail (they are, for example, all power transformers, or insulators, etc.). As noted, the purpose of these procedures is to avoid cumbersome record-keeping for each piece of equipment and, while simplifying the calculation of depreciation, they provide a reasonably good match between actual service lives of equipment and the service lives assumed in the calculations.

With the utilities' increasing use of high-capacity, high-speed computers, the advantage of group depreciation procedures is diminishing, as it is no longer overly cumbersome to update records for a large number of individual assets. Consequently, a utility that has not used such procedures before, may no longer find it advantageous to switch to them now.

It is interesting to note that Saskatchewan Power expressed its view that it would like to abandon Equal Life Group procedures and, instead, have every asset identified and tracked individually. Nonetheless, Saskatchewan Power also reported that is unlikely to change its practices, as its existing capital asset record system would not allow individual monitoring, and the costs of switching to new procedures would be high.

Like NLH, Saskatchewan Power currently depreciates its thermal generating plants as single units and does not identify groups of equipment within each plant. However, Saskatchewan Power reported that it would like to split up its generating units into identifiable components and depreciate them individually. Again, switching to a new approach would be costly, due to the reasons noted above.

No intention to change was expressed by the other surveyed Canadian utilities. As in the case of Saskatchewan Power, once a procedure is in place, it would be costly to change it, regardless of the procedures a utility would actually adopt if it started a system in today's computer environment rather than decades ago.

C. Conclusions

In today's computerized record-keeping environment, the advantages of group depreciation procedures over procedures based on individual records are diminishing. Thus, there would be little rationale for a utility that has not been using group depreciation in the past to switch to that practice now.

Those utilities that have been using group depreciation in the past are nevertheless likely to continue with their existing practice due to the high costs of any change. As for NLH, since it has not adopted group depreciation procedures in the past, it would not be justified to change its practice.

IX

Canadian Survey Results and Service Life Estimates

The responses to the survey of Canadian electric utilities have been summarized in several Tables, which were included in Chapters II, III and VIII. This chapter provides a general overview of the responses and presents a few additional Tables.

A. Use of the various depreciation methods

With three exceptions, utilities use straight line depreciation for the majority of their assets.

1. The straight Line method

As discussed in Chapter II, the straight line method is used by all of the surveyed utilities for at least some of their assets. Seven utilities use the straight line method for practically all of their assets.

2. The sinking fund method

NLH, New Brunswick Power, and Hydro-Quebec are the only utilities among the respondents that use the sinking fund method. Hydro Quebec is using the sinking fund method for most of its assets, but is looking into the possibility of using straight line depreciation for some of its assets. The results of this investigation will not be available until 1998 or 1999.

3. The declining balance method

The declining balance method is not widely used for accounting and rate purposes. It is used for some assets by two utilities:

- Ontario Hydro uses the declining balance method for transport and work equipment and for minor computer equipment.

- BC Hydro uses the declining balance method for motor vehicles.

The declining balance method is used extensively for income tax purposes, as it generates large depreciation expenses in the early years of an asset's service life, giving corporations a form of investment incentive.

4. The unit of production method

The unit of production method of depreciation is used by only one utility: Alberta Power uses this method to depreciate some of its coal leases, as coal is subject to depletion.

5. Other methods

TransAlta Utilities identifies a fifth depreciation method: amortization. It is used by TransAlta for computers, furniture and office equipment. Under TransAlta's definition, this method is similar to straight line depreciation, except that the actual retirement of an asset is not explicitly tracked (i.e., it does not result in an accounting system entry).

B. Comparison of service life estimates

In this section, we compare the service life estimates used by NLH with other selected Canadian utilities. A summary of service life assumptions for the surveyed utilities is presented in Exhibit IX-1.

Note that there may be some differences in the definitions that are used to classify certain utility assets. For example, tools and equipment, as defined by NLH, may include different types of assets than tools and equipment defined by other utilities (discussed later below).

1. Hydraulic generation assets

A comparison of service lives for various types of assets used in hydraulic generation is shown in Exhibit IX-1. Overall, NLH uses service lives that are comparable to other Canadian utilities, or perhaps slightly lower. Only for a very few number of assets (timber booms and hydraulic station switching equipment), are NLH's estimated service lives longer than assumed by other Canadian utilities.

Exhibit IX - 1
Estimated Service Lives (Years)

	N&L Hydro	NS Power	Hydro-QC	Ont. Hydro	Man. Hydro	AB Power	Transalta	BC Hydro
GENERATION								
HYDRAULIC								
Generation Equipment:					50			
Generators	50							50
Generator windings	25						19 - 76	50
Turbines & governors	50							50
Other Specialized Equipment:								
Auxiliary & reservoir power supplies	30							
Static excitation system	25							
Switching equipment	50							30 - 40
Battery banks	15							
Battery chargers	40							
Station service elec. equipment	40							20
Control, metering & relayed equip.	30							20 - 40
Cable trays & conduit	40							
Control & power cables	40							
Forebay lines	30							
Access Station Equipment					40			
Hydro Structures:								
Hydralic valves	50							30
Dams, dikes, intakes	100							100
Spillway & water regulating str.	75							100
Surge tanks	50							100
Canals & tailrace channel	100							100
Civil assets					100			
Gates	50							50
Stop logs, trash racks	50							50
Timber booms	20							10
Penstocks:	50							
- concrete								100
- steel								50
Other:								
Powerhouse crane	75							50
Land improvements	50							100
Roads	50							50
Bridges	25							50
Fencing	20							25
Fire fighting system	25							20
Outdoor lighting system	25							
Sewage disposal system	25							50
Water drainage sump pump	25							
Compressed air system	25							
Cooling system	25							50
Underground storage tanks	25							50 - 100
Other assets, n.e.c.					75			
TOTAL HYDRAULIC		55.4 - 83.4	50	25 - 100		50	55 - 100	

(Generation continued)	N&L Hydro	NS Power	Hydro-QC	Ont. Hydro	Man. Hydro	AB Power	Transalta	BC Hydro
THERMAL								
Thermal generation	30					40 - 95		30
Diesel	20				10			
Gas turbine	25							30
Other						35 - 75		
Structures:						70 - 90		
- wood					30			25
- concrete					15			40 - 100
- metal					15			40 - 50
TOTAL THERMAL		34.4 - 45.0	40	40		35 - 41	35	
TOTAL NUCLEAR			30	40				
OTHER GENERATION			15					
TRANSMISSION								
Wood Poles & Lines	40	42			40 - 60	47	40	35
Concrete Poles & Lines					75		40	
Steel Towers & Lines	50	45			60 - 80	59	40	50
Easements		90			50	75	50	
Road, Trails & Bridges		90			40 - 50			50
Specialized equipment					30 - 35	45	15 - 38	20 - 40
Other					(3) 10 - 20			(5) 50
Conductors:							45	
- overhead		38	50		45	49 - 59		50
- underground			50		30 - 45			
Sub-stations:		35				45	33	
- high voltage	40		40					
- low voltage	30		40					
Bldg, Structures, etc.:							35	
- wood					30			25
- concrete					40			40
- metal					40			40 - 50
TOTAL TRANSMISSION				10 - 100				

.../3

	N&L Hydro	NS Power	Hydro-QC	Ont. Hydro	Man. Hydro	AB Power	Transalta	BC Hydro
DISTRIBUTION								
Poles & fixtures		34			30	37	30	35
Easements		60			50	75	20 - 50	
Underground conduit & subway		65				54	30	35
Equipment		40			30		35	
Bldg, Structures, etc.		45					25 - 30	
Transformers		21			30	30	28	30 - 37
Sub-stations		40	40			40		
Meters & installation		27	15		30	27		30
Street & highway lights		27	10 - 25		25 - 30	23 - 31		
Water heaters			12					
Services		38			25			
Other					(3) 10			
Conductors:								
- overhead		35	30		30	44	35	50
- underground		38	30		30	34		35
TOTAL DISTRIBUTION	30			10 - 100				
GENERAL								
Telecontrol/Sys. control equipment	10 - 20	13	25		20	25	10	10 - 15
Communications equipment		23	10		20	20	13 - 15	10 - 15
Tools & Equipment	5	20 - 36	10		30 - 35	10	10	
Test/Lab Equipment	10	30	10		n/a	10	37 - 47	
Office equipment	10	30	13.3		12	15	15	
Office furniture		30	13.3		12	15	15	
Computer Equipment (H/W & S/W)		7	4		9 - 10	5 - 6	3 - 13	3 - 15
Misc. Equipment		20	(1) 10		n/a	6	35	
Mobile Equipment	3 - 10				(4) 15 - 25		30	25
Vehicles:		13	8					
- light vehicles (cars & trucks)	3				8	6 - 7	9	7 - 8
- heavy vehicles	5				13	14	13 - 18	7 - 12
Buildings, structures:	20 - 36 & 50	40	(2) 25 - 50			37	25 - 70	
- wood					40 - 65			25
- concrete					50 - 75			40
- metal					50 - 65			40 - 50
TOTAL GENERAL				5 - 50				

1. Service facilities.
2. Includes Research Institute Building.
3. Ground line treatment and supervisory.
4. Includes construction equipment, soft-track equipment, truck mounted equipment and trailers.
5. Ductbanks.

When compared to other Canadian utilities, NLH identifies a much larger variety of asset types within its hydraulic generating stations. Only Ontario Hydro uses a greater level of disaggregation when identifying assets for the purposes of assigning service lives. (Ontario Hydro, however, did not provide these details in its response to the survey, as they are apparently very voluminous.)

2. Thermal generation assets

In the asset category that covers thermal generating units, NLH generally assumes a shorter life for associated plant and equipment than most other Canadian utilities. In its depreciation practices, NLH differentiates between three types of fossil-fuel generating stations:

- Conventional coal-fired steam generating stations.
- Diesel generating stations.
- Turbine generating stations.

As noted earlier, within each of these station types, all of the units of property are depreciated at the same overall rate as the plant as a whole. Saskatchewan Power and TransAlta follow this practice for thermal generating plants.

Ontario Hydro and Hydro Quebec both use 40-year lives for their conventional fossil-fired generating units. Nova Scotia Power uses a range of service lives: from 35 years to 45 years.

Like NLH, BC Hydro also assumes a 30-year life for its conventional, fossil-fired generating units. Unlike NLH, however, BC Hydro assumes a longer service life (40 to 100 years) for the associated concrete and metal structures.

Only Manitoba Hydro uses a lower service life estimate than NLH for one type of thermal asset: diesel generating units. They are depreciated over a 10-year period rather than over the 20-year period assumed by NLH.

3. Transmission assets

NLH identifies fewer asset types within the category of transmission plant and equipment than most other Canadian utilities. The service lives that it assumes for these assets, however, are roughly comparable to those used by other Canadian utilities.

4. Distribution assets

NLH depreciates all distribution assets over a term of 30 years. Most of the other surveyed Canadian utilities separate distribution assets into various sub-groups, and allocate different service lives to the different sub-groups.

Nova Scotia Power, for example, identifies a range of service lives within the distribution asset category, from a low of 21 years for transformers to a high of 65 years for underground conduit.

NLH's estimated service life of 30 years for all distribution assets, however, is roughly consistent with the typical service lives assumed by most utilities for most distribution assets. For example, Manitoba Hydro estimates a service life of 30 years for most of its distribution assets, with a few key exceptions. These exceptions are:

- Easements (50 years).
- Services (25 years).
- Ground line treatment and supervisory (10 years).

5. General assets

A review of Exhibit IX-1 indicates that utilities across Canada show wide variations in the service lives they assign to General Assets.

For example, the service lives assumed for office equipment ranges from 10 years (for NLH) to 30 years (for Nova Scotia Power).

As noted earlier, for vehicles and mobile equipment, the service lives assumed by NLH are below the ranges established by other Canadian utilities. The service life assumed by NLH for light vehicles, such as automobiles, is well below that assumed by other Canadian utilities. While NLH assumes a service life of 3 years for light vehicles, all other utilities assume a service life of at least 7 years.

C. Frequency at which service lives are reviewed

Exhibit IX-2 summarizes the frequency with which various utilities review the service lives of their assets. With the exception of BC Hydro, which did not specify the date of its last review, all the utilities surveyed had conducted a service life review within the last five years.

Many utilities have a policy of reviewing major and broad asset categories at least once every five years. However, as noted, those utilities use group depreciation procedures, which do require periodic studies.

D. Accounting for service life revisions

Service lives are often adjusted after a depreciation study is completed. When service life estimates are adjusted, depreciation rates need to be adjusted to reflect the revised dates of expected retirements.

It is shown in Exhibit IX-2 that all of the surveyed utilities handle changes in depreciation rates prospectively. In other words, the undepreciated cost of the associated fixed asset is amortized over the remaining life of the asset concerned, where the remaining life of the asset is adjusted to reflect revised service lives. Accordingly, no adjustment is made either to:

- the balance sheet amount shown for accumulated depreciation outstanding at the time service lives are revised;
- reported net income for the year of the revision or for prior years.

E. Regulation

Exhibit IX-3 shows the forms of regulation to which electric utilities are subjected in Canada. Most of them are now regulated on the basis of Rate of Return on equity, or capital. Exceptions are, Manitoba Hydro, which is regulated on the basis of interest coverage, and Ontario Hydro, whose rates are not formally regulated.

F. Conclusions

The general conclusions from the utility survey are:

- Many more Canadian electric utilities use straight line depreciation than sinking fund depreciation.
- Almost all utilities use some form of group depreciation, for at least some of their assets, and NLH is the only utility that does not.
- The average service lives assigned by Canadian utilities to their assets are mostly in line with those assigned by NLH. However, NLH assigns slightly

Exhibit IX - 2
Depreciation technique

	Review/revise remaining service lives on periodic basis? If so, when?	Did revision include adjustment of accumulated depreciation?
NS Power	- 1993, 1995	- No
NB Power Corp.	- Review asset service lives every 5 years.	- No
Hydro-Quebec	- Review each major asset category every 5 years.	- No, changes applied prospectively.
Ontario Hydro	- For all assets, annually review service lives and estimated decommissioning costs. - Also annually review the amortization rates for non-operating reserve facilities and deferred construction projects.	- No, changes applied prospectively.
Manitoba Hydro	- 1988, 1995.	- No.
Sask. Power	- Every 3-5 years. - Last reviews: 1991, 1996.	- No, changes in estimated life or reserve are applied prospectively.
Alberta Power Corp.	- Review periodically. - Last reviews: 1991, 1995	- No, changes applied prospectively over remaining service life of asset.
Transalta Utilities	- Revise average service lives with each depreciation filing. - Last revisions: 1991, 1996.	- No, deficit or surplus in reserve is amortized over the weighted average of the remaining life of the vintage balance. Adjustments made prospectively.
BC Hydro	- Periodically.	- No, changes applied prospectively over remaining life of the asset.

Exhibit IX - 3
Regulation

	Regulatory Body	Basis for Regulation	Comments
NS Power	Utility & Review Board of Nova Scotia.	ROR on common equity.	
NB Power Corp.	New Brunswick Public Utilities Board.	Price cap.	
Hydro-Quebec	Corporate bylaws and contracts subject to approval from Quebec government.	ROR on rate base after accounting for all operating expenses, interest on debt and fixed asset depreciation (max. 50 years).	Regulation will become the purview of the *Regie de l'Energie du Quebec* once the enabling legislation takes effect. The Regie will be responsible for (a) setting rates and conditions for transmission and distribution, (b) approval of integrated resource plans.
Ontario Hydro	Board of Directors and Ontario Energy Board (latter is non-binding).	Cost of supplying power. Costs include: O&M charges, depreciation, and debt service.	
Manitoba Hydro	The Public Utilities Board of Manitoba.	Interest coverage.	
Sask. Power	Parent company and Provincial Cabinet.	ROR on rate base.	
Alberta Power Corp.	Alberta Energy & Utilities Board.	ROR on rate base.	Deregulation pending the passage of additional legislation.
Transalta Utilities	Alberta Energy & Utilities Board.	ROR on rate base (mid-year).	Deregulation pending the passage of additional legislation.
BC Hydro	B.C. Utilities Commission.	ROR on equity.	

shorter lives to its hydraulic assets than the other utilities, also shorter lives to its thermal generating stations and much shorter lives to its vehicles.

Recommendations for adjusting the service lives of NLH's assets were made in Chapter V.

X

Summary of Conclusions

Depreciation method

The sinking fund method of depreciation provides greater equity among present and future users of electric power, as it allows the power users to derive the same net benefits from the use of a particular asset throughout its entire service life.

The only two justifications for a higher total of depreciation and interest expense during the early years of an asset, from the perspective of equity among customers, would be:

(1) an expected increase in maintenance costs over the asset's lifetime, and

(2) declining value due to technological advances and obsolescence.

Such trends are experienced for certain types of machinery, equipment and buildings.

Regarding impacts on rate payers this study found that switching the depreciation method to straight line for all assets would have cost NLH's residential customers approximately $7.00 per month in that year. This amount would decline below zero after 8 years, and would change to negative impacts of about $7.00 (in 1997 dollars) around approximately 2026.

Because of the time factor, Newfoundland residents would be negatively affected by a change to straight line depreciation.

Salvage

It is recommended that for assets with an original acquisition cost of less than $500,000 and for all assets that have an estimated future salvage value (in inflated terms) of less than 10 percent of their acquisition cost (in original terms) salvage should be recognized in NLH's Income Statement at the time it is incurred. This treatment is defined as Alternative 1.

For assets that have acquisition costs in excess of $500,000 **and** an estimated net salvage values in excess of 10 percent (referred below as "major" assets), the following alternatives exist:

- When the asset is expected to be replaced after retirement by an asset of the same nature at the same site (most likely in an upgraded or improved form) the net salvage value related to the retired asset should be combined with the acquisition and construction costs of the new asset. As explained earlier, this approach is equitable because (1) future users are expected to enjoy capital cost savings attributable to the pre-existence of a plant at the site and (2) future users are deprived from the use of still useable assets that were sold on disposal. The users of the replacement asset will therefore be (1) legitimately charged with the net retirement costs of the old asset and (2) legitimately credited with the proceeds gained from the disposal of the old asset or any part thereof. The treatment described in this paragraph is defined as Alternative 2.

- When a significant "major" asset is retired without replacement at the same site, and net salvage costs are incurred as a consequence of the asset's removal and/or the rehabilitation of its site, they can be treated in two ways:

  - If the decision to abandon a site was the result of a feasibility study that indicated that, after having included all removal and rehabilitation costs incurred at the old site into the study, the transfer of operations to a new site was still beneficial to NLH and its customers, it is equitable to charge future customers with the net salvage costs. That can be achieved by amortizing the costs over a period of five years for amortizable amounts of, say, less than $500,000, and ten years for larger amounts. This treatment is defined as Alternative 3.

  - When the removal of an asset and the rehabilitation of its site is performed as an undertaking or commitment related to external reasons, such as complying with urban or regional development plans, or satisfying public objectives, or responding to the terms of environmental and other approval processes, the net salvage costs should be built into the depreciation rates of the asset throughout its service life. This should be done in the form of a percentage mark-up on the depreciation rate calculated on the basis of the asset's original acquisition cost. The mark-ups or "salvage factors" can be calculated on the basis of engineering estimates. If properly calculated, they will produce a surplus in accumulated depreciation by the end of the asset's service life that is equal to the estimated net salvage costs in inflated terms. This treatment is defined as Alternative 4.

It is not practical to apply Alternative 4 to existing assets after they have passed a significant portion of their service lives. It is quite unlikely, however, that any of

NLH's existing assets would fall into that category. If so, the application of Alternative 3 would be a logical option.

In theory, Alternatives 3 and 4 can also be used for the treatment of positive net salvage, the occurrence of which is expected to be rather exceptional for "major" assets.

The final alternative that was described in this chapter was Alternative 5. That alternative is identical in "bottom-line" terms with Alternative 4 but differs in presentation in NLH's financial statements. Alternative 5 consists of the establishment of an explicit reserve account for the accumulation of that portion of the depreciation reserve that is intended to cover future net salvage costs. It is used by utilities primarily when the establishment of a site rehabilitation reserve responds to public concerns. It is not likely that this alternative would be used by NLH.

Prime assets and coding of assets

As in the 1986 study, we consider NLH's current approach to depreciating prime assets appropriate.

NLH may consider **coding** its units of property in such a manner that it will be easy to determine the total number of like units and their total acquisition costs, by installation year, or in total. The coding would make it possible to compare the actual service lives of the assets with their assigned service lives on a statistical basis.

Many electric power utilities use a coding system defined as a Uniform System of Accounts, which identifies a particular type of asset (e.g. as a "current transformer", "compressor", "control cable", etc.). Such coding facilitates the statistical analyses required for a variety of purposes, and makes it possible to check accounting practices on a continual basis.

The service lives of major prime assets that approach the end of their previously estimated service lives but are expected to be able to remain in service much longer should be revised as soon as the need for a service life extension becomes apparent. Such service life extensions can be based on engineering Condition Surveys.

When a minor equipment is installed within a prime asset that has been fully depreciated it should be depreciated separately if its cost exceeds $50,000. If its cost is lower the minor equipment may be expensed.

Service lives

NLH's service life estimates and corresponding depreciation dates were found to be appropriate, with the following exceptions:

NLH's service life estimates and corresponding depreciation rates were found to be appropriate, with the following exceptions:

- With respect to assets with estimated service lives in excess of 20 years, historical evidence is insufficient to conduct a definitive analysis. Nonetheless, on the basis of the observed small number of retirements of those assets, it can be stated that their actual service lives are probably longer than originally estimated. In fact, it is becoming increasingly apparent that the service lives of thermal generating plants will almost certainly be longer than estimated.

- Accordingly it is recommended that engineering Condition Surveys shall be conducted at those thermal generating plants that are approaching the end of their presently estimated service lives, with a view to possible extensions of their remaining lives and corresponding adjustments to their depreciation rates. The Holyrood generating units were identified as prime candidates for such revisions.

- An analysis of other assets with service lives up to 20 years indicated that NLH's early retirements are well in balance with those assets that are fully depreciated and still in service (late retirements). The analysis indicated that NLH's average annual write-offs attributable to early retirements are quite close to the reductions in depreciation expenses attributable to those assets that continue providing service at zero net book value. It was concluded from this finding that NLH's service life estimates for most assets with service lives of up to 20 years are appropriate, except for vehicles.

- Vehicles appear to have longer actual service lives than estimated by NLH. On the basis of KPMG's analysis, it is recommended that the service lives of passenger cars be extended from 3 to 5 years and that of snowmobiles and pick-up trucks shall be set at 6 years.

Engineering review

All aspects of the engineering appraisal of the Asset Sample supports the view that NLH's fiscal policy regarding asset depreciation reasonably reflects the actual asset retirements likely to be experienced. In particular, the service lives selected by NLH for the purpose of asset depreciation reflect expected service lives and generally agree with those adopted by other utilities. Appropriate operation and maintenance procedures and retirement and replacements practices are required if full service life expectancy is to be realized. In this respect, NLH's preventative maintenance planning and execution were found satisfactory and fully supportive of the selected service lives. NLH's operational record compares favourably with that of other utilities, lending further support to the competency of NLH's asset management.

As noted, the make-up of the Asset Sample was developed in order to reasonably reflect the majority of NLH's assets in terms of size, type, service conditions and age. It can be reasonably suggested, that with the remainder of NLH's assets, not properly represented by the Asset Sample, NLH exercised the same degree of prudence in selecting service lives and effort for maintaining the equipment. Accordingly, NLH's total policy with regard to asset management can be considered satisfactory.

With respect to service lives it was noted earlier in the report, and confirmed by the Engineering Study, that the present service life estimates of some of NLH's thermal generating plants appear to be too low. Accordingly, it is recommended that appropriate Condition Surveys be conducted for the Holyrood generating station, as well as for the Hardwood and Stephenville gas turbine stations, with a view to extending their service life estimates.

Group procedures

In today's computerized record-keeping environment, the advantages of group depreciation procedures over procedures based on individual records are diminishing. Thus, there would be little rationale for a utility that has not been using group depreciation in the past to switch to that practice now.

Those utilities that have been using group depreciation in the past are nevertheless likely to continue with their existing practice due to the high costs of any change. As for NLH, since it has not adopted group depreciation procedures in the past, it would not be justified to change its practice.

Utility survey

The general conclusions from the utility survey are:

- Many more Canadian electric utilities use straight line depreciation than sinking fund depreciation.

- Almost all utilities use some form of group depreciation, for at least some of their assets, and NLH is the only utility that does not.

- The average service lives assigned by Canadian utilities to their assets are mostly in line with those assigned by NLH. However, NLH assigns slightly shorter lives to its hydraulic assets than the other utilities, also shorter lives to its thermal generating stations and much shorter lives to its vehicles.

Appendix A

Literature Review Regarding Salvage and Related Issues

A. Sources

In the course of this study, we contacted various regulatory agencies and institutes to identify studies and reports that could bear on the issues facing NLH. Publication catalogues from the following agencies were reviewed:

- National Association of Regulatory and Utility Commissioners (NARUC).
- National Regulatory Research Institute (NRRI).
- Edison Electric Institute (EEI).
- American Public Power Association.
- Canadian Electrical Association.

From these agencies, we selected studies pertaining to depreciation policies and procedures for electric utilities, especially those dealing with the topic of accounting for net salvage.

We also conducted a literature search, using on-line database search tools, to identify articles published in academic and accounting journals. The following articles were reviewed:

- John S Ferguson: "Power Plant Removal Costs", Journal of the Society of Depreciation Professionals, Vol. 5, No. 1, 1993.
- Bob White and William Welke: "Accounting for Negative Net Salvage in Public Utilities", Journal of the Society of Depreciation Professionals, Vol. 4, No. 1, 1992.

- Edison Electric Institute, Depreciation Accounting Committee: "An Introduction to Net Salvage of Public Utility Plant", date unknown.

- Edison Electric Institute, Depreciation Accounting Committee: "An Introduction to Depreciation of Public Utility Plant", 1983.

- Bob White and Azim Houshuar and Shelley Brown: "Forecasting Salvage and Cost of Removal", Journal of the Society of Depreciation Professionals, Vol. 1, No. 1, 1993.

- National Association of Regulatory Utility Commissioners: "Public Utility Depreciation Practices", August 1996.

B. The trend to increasing negative net salvage values

Two factors account for the increasing incidence of negative net salvage value in the U.S.:

- Environmental regulations have become stricter. For example, guidelines for the removal of PCBs have become much more stringent over time. Environmental agencies and regulators now often require that utilities, after retiring an asset without replacement, restore the generating site to its original state.

- Labour costs have tended to increase faster than inflation. Labour costs are typically incurred in removing or dismantling utility assets, and they are often significant portions of such removal costs. Salvage values, on the other hand, often reflect only the scrap value of the materials recovered upon the removal of an asset. Such scrap values have tended to increase more slowly than the general rate of inflation.

C. Published estimates of site decommissioning costs

In the article "Power Plant Removal Costs", [1] John Ferguson analyzes site-specific estimates for the removal costs of nearly 400 steam generating units (burning all types of fuel) and over 100 internal combustion units, including both diesel and combustion turbine engines.

[1] *Journal of the Society of Depreciation Professionals, Volume 5, #1, 1993*

The estimates were made between 1978 and 1992, and calculated at the price levels in effect at the time the estimates were made. The author of the study than converted these estimates to 1992 dollars.

Average costs of removal for various types of generating stations are summarized in the Exhibit below.

Exhibit A-1
Costs of removal

	Net Salvage Factor [1] (in current dollars)	Removal Cost per KW (in constant 1992 US$)
Steam Units		
Oil and Gas	-50.6%	$29
Coal	-46.9%	$39
Internal Combustion Units		
Diesel	-22.0%	$3
Combustion Turbine	-5.4%	$3

On a per KW basis, removal costs for coal steam units are higher than for oil and gas units ($39 per KW vs. $29 per KW at 1992 price levels). Estimated costs of removal for internal combustion units, both diesel and combustion turbines, are much lower than for steam plants, at only US$ 3 per KW at 1992 price levels.

The Exhibit also shows the estimated average net salvage factors for the different types of units in the sample analyzed. The salvage factors are based upon estimates of future removal costs, taking into account removal costs at then-current prices and expected inflation trends until retirement. These removal costs were then expressed as a percentage of the depreciable investments applicable to the units. The details of these calculations were not provided.

The average figures presented in Exhibit need to be interpreted with caution. Individual estimates show a wide range of values, from less than US $ 10 per KW to over US $150 per KW, with the estimates reported at 1992 price levels. The data also show significant economies of scale in site removal: larger units show much lower costs of removal per

[1] *Net positive or negative salvage as a percentage of acquisition costs in current dollar terms (considering actual acquisition costs and inflated costs for salvage).*

KW than smaller units. In particular, units over 100 MW tend to show much more stable and lower costs of removal.

The study also discusses the most common factors that may influence removal costs in a significant way. They include:

- Insulation containing asbestos. Generating units built prior to the early 1970s are more likely to have insulation containing asbestos than units built subsequently. Removal and disposal of asbestos insulation is very expensive, and must often be done prior to the demolition of the rest of the structure. In nominal terms, asbestos removal costs can equal as much as one-third of the original cost of the plant.

- Modern boiler units are often hung from their top from a multi-story steel super-structure. This makes them much more expensive to dismantle than older-style boilers that sit upon foundations.

- Fuel gas desulphurization units (scrubbers) can add to the complexity of a power station and, accordingly, to the costs of its removal. They may also produce by-products that require special handling.

The issue of salvage, as it may apply to NLH, was discussed in detail in Chapter III.

Appendix B

Group Depreciation Procedures

This Appendix contains a brief description of group depreciation procedures.

1. Average Life Group (or "Broad Group") procedure

Under the Average Life (or Broad Group) depreciation procedure, all "like" assets are placed in one group. In practice, this means that the acquisition cost of a new asset is added to the fixed asset balance of the group to which the asset is assigned.

If the units within such a group have an expected life of, say, 20 years, a depreciation rate of 1/20, or 5 percent, will be used to depreciate this group. In any given year, the depreciation expense associated with the group (or "pool") will then be 5 percent of the beginning year's balance in the fixed (gross) asset account.

In individual depreciation procedures, when an individual asset is retired, the initial capital cost of that asset is removed from the gross asset account. The portion applicable to that asset is also removed from the accumulated depreciation account. Under group depreciation procedures, the individual asset does not have its own account. If, in a 20-year asset class, the particular asset happens to last for only 15 years, the unit will have been under-depreciated and the asset's acquisition cost would not have been recovered through to depreciation expenses over the asset's life.

Although the asset has been under-depreciated, under group methods no write-off is taken. The **full** acquisition cost of the retired item is removed from both the gross asset and accumulated depreciation accounts. As this particular item has not yet been fully depreciated, the accumulated depreciation account is thus reduced by a greater amount than necessary.

Conversely, if a piece of equipment were to remain in service longer than its originally estimated service life, it would continue to be depreciated as long as it was in service. Thus, it will be over-depreciated and the accumulated depreciation account will increase by a greater amount than necessary.

Under this procedure, it is assumed that the two types of error described above cancel each other over the long term.

To the extent that they do not cancel each other, there will be a limited degree of misrepresentation in the utility's accounts. That "misrepresentation" is corrected periodically through depreciation studies, when accurate comparisons are made between assets actually in service and the assets presumed to be in service by the group procedure.

2. The Vintage Life Group procedure

The Vintage Life Group procedure is a somewhat more refined version of the Average Life Group procedure. In the Vintage Life Group procedure, similar assets acquired within the same year are grouped together. Otherwise, this procedure works in the same manner as the Average Life Group procedure.

This procedure is not more accurate than the Average Life Group procedure but it shows explicitly the amount of under-depreciation and over-depreciation of a particular asset group and makes the periodic depreciation studies easier. For example, in 1996 the procedure would show the value of assets with an assigned 20-year life that were acquired after 1976 and already retired (i.e. under-depreciated) and the value of assets acquired before 1976 and still in service (i.e. over-depreciated).

3. The Equal Life Group procedure.

The Equal Life Group (ELG) procedure is a further refinement of the Vintage Life Group procedure. The difference between the Vintage Life Group procedure and the ELG procedure is the recognition of the existence of "retirement dispersion" in the depreciation rate calculation.

Under the ELG procedure, the assets assigned to a single Vintage Group are further divided into sub-groups: each sub-group is expected to have a different service life, according to a probability function, with the mean being equal to the average service life assigned to the asset class.

The distribution of units into these sub-groups is based on studies of utility asset mortality. This experience provides data on the "dispersion" of retirements that are likely to occur. By dispersion, we are referring to the fact that say, 15 percent of the assets with an expected average life of 40 years may, in fact, last only 30 to 35 years, 60 percent 35 to 45 years, 15 percent as long as 45 to 50 years, while 5 percent may last less than 30 years, and 5 percent more than 50 years. The distribution of actual service lives around a mean service life is what is defined as mortality dispersion.

While the previously described procedures simply assume that all units survive for the expected average 40 year service life, the ELG procedure requires an estimate of the percentage of units that will reach a particular age (e.g., 36, 37, 38, 39, 40, 41, 42 years, etc., up to the maximum expected life span).

In the ELG procedure, the total acquisition costs of the assets acquired each year in a group are assigned to expected life-span sub-groups in accordance with empirical probability functions, described by the so-called "Iowa curves", developed several decades ago by the University of Iowa. There are several such curves: some with narrow ranges of life-spans, others with wider ranges, some skewed toward longer lives, some toward shorter lives (i.e., having longer or shorter "tails" on the upside or downside). The curve that best fits the experience with a particular kind of asset is assigned to it by the depreciation experts of the utilities, based on the practices of the industry and many years of own experience.