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Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Line Businesses

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ABBREVIATIONS USED IN THE HANDBOOK

Abbreviation	Term
a	Stranded aluminium conductor
Al	Aluminium
c	Stranded copper conductor
CAPM	Capital Asset Pricing Model
Cu	Copper
DRC	Depreciated Replacement Cost
DV	Depreciated Value
EBIT	Earnings Before Interest and Tax
ELB	Electricity Line Business
EV	Economic Value
FCF	Free Cash Flow
h	HDPE sheath
hc	Helically wound copper screen
HV	High Voltage
kV	kiloVolt
kVA	kiloVoltAmpere
kWh	kiloWatt hour
LV	Low Voltage
MEA	Modern Equivalent Assets
MW	MegaWatt
NOPAT	Net Operating Profit after Tax
NRV	Net Realisable Value
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
ORC	Optimised Replacement Cost
PV	Present Value
Regulations	Electricity (Information Disclosure) Regulations 1999
RC	Replacement Cost
RL	Remaining Life
SWER	Single Wire Earth Return
TL	Total Life
UDV	Undepreciated Value
WACC	Weighted Average Cost of Capital
x	XLPE insulation

PREFACE

Purpose of the Handbook

1 This handbook has been published by the Chief Executive of the Ministry of Economic Development pursuant to section 170(1)(g)(i) of the Electricity Act 1992. The methodology in this handbook is to be used to value the system fixed assets of Electricity Lines Businesses (ELBs), as defined by the Electricity (Information Disclosure) Regulations 1999 and subsequent amendments. The sole purpose of this valuation methodology is to support the disclosure of performance measures under Regulation 15 of the Electricity (Information Disclosure) Regulations 1999 (the regulations).

2 This edition of the Optimised Deprival Valuation (ODV) Handbook for Electricity Line Businesses supersedes the Handbook for Optimised Deprival Valuation of Transpower dated 7 July 1994, the Handbook for Optimised Deprival Valuation of Electricity Line Businesses dated 23 June 1994, the Handbook for Optimised Deprival Valuation of Electricity Line Businesses dated 28 May 1998, and the Handbook for Optimised Deprival Valuation of Electricity Line Businesses dated April 1999.

Coverage of the Handbook

3 The handbook covers the valuation of system fixed assets using the ODV methodology. The handbook does not cover the valuation of non-system fixed assets that ELBs may own. The treatment of non-system fixed assets and current assets is covered by generally accepted accounting practice (GAAP).

Defining the Valuer(s)

4 For the purposes of this handbook, the term Valuer(s) refers to any party (or parties) responsible for the preparation of all or any part of the valuation.

Frequency of Preparation of ODVs

5 The regulations require ELBs to complete a valuation based on the ODV methodology at least every three years or whenever there is a cumulative increase or decrease of 10% or more in the capacity of the electricity system (as measured in system length or transformer capacity) since the last ODV, whichever occurs first. The valuation must be carried out as at a specific date. ELBs may undertake valuations on a more frequent basis if desired.

Disclosure of ODV Reports

6 The regulations require all ELBs to disclose annually the value of their system fixed assets and make a valuation report available to the general public for inspection. The valuation report must state the valuation date, and disclose the following information:

(a) the asset replacement costs and lives used, the quantity of assets in each category of asset replacement costs and lives used, and the replacement cost of the line business system fixed assets; and

(b) details of the amount of depreciation charged, and the depreciated replacement cost of the line business system fixed assets; and

(c) details of the components of the line business system fixed assets which were optimised, and the optimised depreciated replacement cost of the line business system fixed assets; and

(d) details of the comparison of optimised depreciated replacement cost with economic value for those parts of the line business system fixed assets which may not be able to sustain tariffs based on optimised depreciated replacement cost (including any specific assumptions used for the purpose of calculating the economic value of that part of the line business system fixed assets); and

(e) the optimised deprival valuation of the line business system fixed assets.

7 *Optimisation:* the valuation report must also include the following information about the optimisation undertaken in preparing the valuation report:

(a) a description of the methodology used by the valuer in undertaking the optimisation;

(b) the existing load and load forecast at the end of the relevant planning period for each part of the network, including each point of connection, each zone substation and each individual distribution feeder;

(c) details of the ELB's quality of supply criteria used as the basis for optimisation;

(d) a full explanation of the reason for not optimising any part of the network where the quality of supply is greater than the disclosed optimisation criteria, including relevant details of any specific customer non-standard contract; and

(e) a schedule of all network optimisation and details of the valuation impact of each individual optimisation including details of the assets removed as Stranded Assets;

8 *Economic Valuation:* the valuation report must also include the following information about the economic valuation undertaken in preparing the valuation report:

(a) a description of the methodology used by the valuer in undertaking the economic valuation;

(b) a schedule of all feeders required to be tested for economic valuation and details of the economic valuation calculations used to assess those feeders; and

(c) details of the maximum sustainable tariff used as the basis for economic valuation.

9 Form 7 being the certificate related to ODV Valuation Reports of electricity line businesses including Transpower must include, amongst other things, the Replacement Cost (RC), the Depreciated Replacement Cost (DRC), the Optimised Depreciated Replacement Cost (ODRC), and the Optimised Deprival Valuation (ODV), of the line business system fixed assets.

Tariff Setting

10 Tariff setting is an independent process from preparation of ODVs. There is specifically no regulatory requirement that prices be determined on the basis of system assets being valued according to ODV.

General

11 The handbook has been prepared by the Energy Markets Regulation Unit (EMRU) within the Resources and Networks Branch of the Ministry of Economic Development. ELBs encountering problems with the handbook are welcome to discuss issues arising with the EMRU. The Ministry of Economic Development will monitor the application of the handbook, with a view to subsequent modification in the light of experience.

Energy Markets Regulation Unit
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WELLINGTON

PART ONE: INTRODUCTION

1.1 This handbook has two principal sections:

* Part Two: General Overview of the ODV Valuation Approach
* Part Three: Practical Valuation and Mandatory Procedures

1.2 Part Two gives a general description of the approach to valuing system fixed assets using the Optimised Deprival Valuation (ODV) methodology, while Part Three (which is supported by a series of appendices) gives the details of the practical approach which must be applied to valuation. It is mandatory that Part Three be followed in carrying out valuations for the purposes of complying with the Electricity (Information Disclosure) Regulations 1999 as amended by the Electricity (Information Disclosure) Regulations Amendment Regulations 2000.

PART TWO: GENERAL OVERVIEW OF THE ODV VALUATION APPROACH

Introduction

2.1 The mandatory valuation approach set out in Part Three is based on the application of the Optimised Deprival Value (ODV) methodology. The approach applies to both local line businesses and to Transpower.

2.2 The aim of applying the ODV methodology is to value the assets at the level at which they can be commercially sustained in the long term, and no more. The resulting value should be equal to the loss to the owner if they were deprived of the assets and then took action to minimise their loss.

2.3 The value of the assets derived in this way may differ from their current book value. Book value is typically based on expenditures made over the years and may bear little resemblance to the ODV value.

The Optimised Deprival Valuation Methodology

2.4 The ODV of system fixed assets is the minimum of Optimised Depreciated Replacement Cost (ODRC) and Economic Value (EV). The ODRC is the replacement cost of the existing system fixed assets at Modern Equivalent Asset (MEA) value, which have been optimised from an engineering standpoint and depreciated according to their age. In some cases, because of constraints on tariffs, it may not be possible to make a normal rate of return on segments of the network when the segment assets are valued at ODRC. That is, the segment is not self-sustainable in the long term. In such cases the EV value, a value lower than the ODRC, is applicable to the segments.

2.5 The ODV methodology involves the following steps:

(a) Calculation of Optimised Depreciated Replacement Cost (ODRC)

(i) preparing a detailed asset register

(ii) calculating Replacement Cost (RC) using Modern Equivalent Asset values

(iii) assessment of depreciation (DRC)

(iv) system optimisation

(v) determination of Optimised Depreciated Replacement Cost (ODRC)

(b) Determination of Economic Value (EV)

(c) Determination of the ODV as the lesser of the ODRC and the EV.

Optimised Depreciated Replacement Cost (ODRC)

2.6 The ODRC measures the cost of replicating the system, using Modern Equivalent Asset values, in the most efficient way possible, from an engineering perspective, given its service capability and *the age of the existing assets.*

Preparing a Detailed Asset Register

2.7 The basis for undertaking an ODV valuation is the collation of a comprehensive asset register of the ELB's system fixed assets and their configuration. Such asset registers should contain data on the quantity, location, physical condition, age and maintenance of the ELB's assets.

Determination of Replacement Cost (RC)

2.8 The next step is to value the network at replacement cost. The replacement cost is determined as the cost of replacing assets with Modern Equivalent Assets (MEA). It is important that objective values be applied consistently across the industry, and accordingly Part Three prescribes maximum values that are not to be exceeded.

Assessment of Depreciation to Determine Depreciated Replacement Cost (DRC)

2.9 Once the quantities and replacement costs of assets have been determined, costs need to be depreciated in cases when the existing asset's remaining life is less than the life expected from a new asset. The depreciation recognises the limited Remaining Life (RL).

2.10 The RL of an asset can be determined as the (Total Life (TL) – Age of Asset). It is important that objective lives be applied consistently across the industry, and accordingly Part Three prescribes maximum lives for assets that are not to be exceeded.

System Optimisation

2.11 The objective of optimisation is to determine a value of system fixed assets that is the counterpart to the market value of the assets of a business in a competitive market – that is the value of the assets on which such a business could earn a normal rate of return commensurate with the risk that business faces.

2.12 Optimisation consists of removing any surplus assets or excess capacity from the network configuration and the network elements, given the required level of service and network capacity.

2.13 It should be stressed that optimisation is not concerned with improving the system from its current state. The system should not be notionally re-designed to be better than it is (whether in terms of capacity, or other standards) where this would cost more. Optimisation leads only to reductions in the cost of the system for valuation purposes.

2.14 Where optimisation has taken place there is the question of what depreciation to apply to the notional replacement assets. Part Three specifies that the notional replacement assets be depreciated assuming that they have the same proportion of their TL remaining as do the assets they are replacing.

Determination of Optimised Depreciated Replacement Cost (ODRC)

2.15 To determine the Optimised Depreciated Replacement Cost it is necessary to exclude from the valuation those network assets which have been optimised and include the modern equivalent optimised depreciated assets.

Economic Value (EV)

When to Apply

2.16 System fixed assets are valued at their economic value when it would not be possible for them to earn sufficient long-run profits to provide an appropriate return on the ODRC of the assets. That is, the assets are not commercially sustainable in the long-run.

2.17 Generally networks should be partitioned into segments for EV analysis. It is important that economic value tests be applied consistently across the industry. Accordingly, Part Three prescribes the minimum approach to segmentation and to performing the economic value analysis of system fixed assets.

2.18 The revenue that can be derived from system fixed assets is determined from assessing the profit maximising long-run line tariffs that could be applied to consumers. It is important that objective profit-maximising long-run line tariffs be applied consistently across the industry, and accordingly Part Three prescribes the maximum line tariff that can be applied.

How to Determine the EV Value

2.19 The economic value ("EV") of any system fixed assets in a segment of the network is the maximum of the net realisable value and the present value of the after-tax cashflows attributable to that segment, less any initial investment in non-system fixed assets and working capital associated with the asset. The items comprising the Present Value are:

- the after-tax operating cashflows;
- less any capital expenditure performed on the segment;
- plus the proceeds from any disposals of assets on the segment;
- less any increase in working capital;
- plus the estimated economic value of the system fixed asset at the end of the period of analysis;
- less any initial investment in working capital; and
- less any initial investment in non-system fixed assets.

That is, the principal PV equation is:

$$PV = \sum_{t=1}^{t=k} \frac{ATOCF_t - CapEx_t + Disposals_t - \Delta WC_t + EV_k + NSFA_k + WC_k}{(1+WACC)^t} - NSFA - WC$$

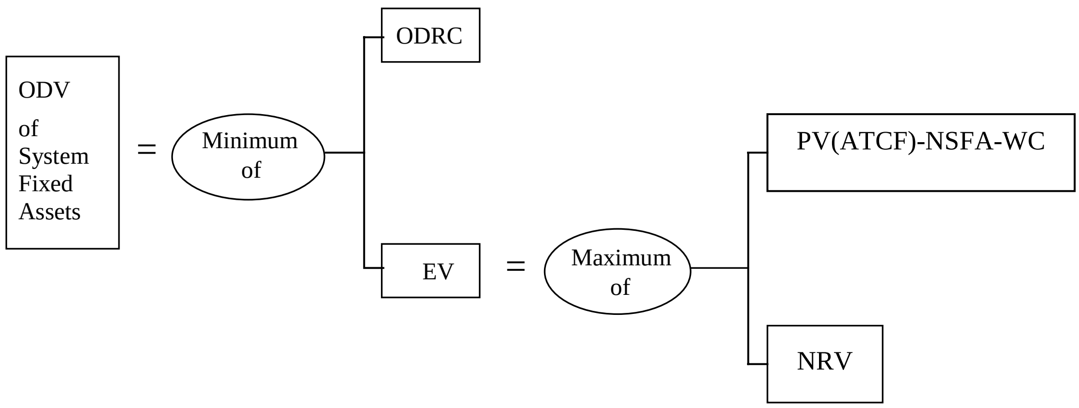
Where k is the period of analysis for the segment being valued and WACC is the weighted average cost of capital for the ELB.

Putting ODRCs and EVs Together

2.20 As indicated previously the ODV of the system fixed assets is the minimum of the ODRC and the EV. Figure 2.1 summarises how the decisions for determining EV and making the choice between EV and ODRC, discussed in the preceding paragraphs, fit together.

2.21 The overall system ODV is determined by the aggregation of the ODRCs for those assets to which an ODRC valuation is applicable, and the EVs for those assets for which an EV valuation is applicable.

Figure 2.1 Determination of ODV



PART THREE: PRACTICAL VALUATION AND MANDATORY PROCEDURES

Introduction

3.1 The valuation procedures presented here in Part Three differ from those given in Part Two in that more steps are included. This is in recognition of both the practicalities of undertaking valuations and the requirements of regulation 20 of the Electricity (Information Disclosure) Regulations 1999, and the information to be included in valuation reports about the optimisation and economic valuation procedures.

3.2 Disclosure of the individual items listed in regulation 20 is designed to provide for transparency of the valuation process carried out by individual ELBs by making clear the effect of both optimisation and the application of EVs on the final ODV valuation. The process of optimisation and the application of EVs must be backed up by disclosed criteria for the quality of supply and forecasts for load growth, together with details of the optimisation and economic valuations undertaken.

Valuation of the System Fixed Assets at Replacement Cost (RC)

3.3 There are two steps in the determination of replacement cost:

(a) preparing a detailed asset register;

(b) valuing the assets at Modern Equivalent Asset costs.

Preparing a Detailed Asset Register

3.4 All ELBs should have a comprehensive database for their assets. Ideally, for the purposes of carrying out optimisation and the application of EVs, the database should be computerized to facilitate sorting and reporting according to various numbers and levels of sort key (e.g. asset type, voltage level, capacity, network segment or location).

3.5 To be able to carry out adequate optimisation and application of EVs it will generally be necessary that the network register is built up from or can be divided into relatively small segments.

3.6 Appendix A gives the minimum classification of system fixed assets expected to be used by local ELBs.

3.7 As well as system fixed assets, stores and spares that can be connected to the network in place of existing network equipment may be valued as part of the ODV. ELBs must have a record of stores and spares, preferably in a computerised ledger system. In cases where complete records are unreliable, it may be necessary to undertake a stocktake for valuation purposes. The quantities of items held in stock must be consistent with the historical reliability of the equipment, the number of items installed on the network and an ELB's disclosed quality criteria. Stores and spares must be shown as a separate line item in the valuation report.

3.8 Asset registers should be checked for consistency and sample checks should be carried out in the field to verify that the quantities and ages recorded are accurate within reasonable limits. Guidance as to what constitutes "reasonable limits" should be taken from the significance of each item and its effect on the accuracy of the overall valuation.

3.9 The system fixed asset register should be in a form that facilitates scrutiny of the register and a ready understanding of how it is composed.

Exclusion of Assets

3.10 Assets such as head office buildings, office furniture and equipment, motor vehicles, tools, plant and machinery, works under construction, consumers' meters and consumer-based load control relays, and non-network land and stores and spares should not be included in the asset register of system fixed assets that is used as a basis for preparing the ODV valuation of system fixed assets.

Valuing the Assets

3.11 The system fixed assets are to be valued using the Replacement Costs (RC) of Modern Equivalent Assets (MEA) that would be installed today in order to provide the same level of service as the assets in place. The MEA should not reflect improvements required by legislative changes made since the assets were first built or installed, if such improvements result in higher replacement costs and if the existing assets have not yet had to comply with the additional requirements, e.g. where grandfathering provisions apply. The maximum values for MEA for ELBs which are not to be exceeded are set out in tables in Appendix B. Lower values can be applied but the maxima are not to be exceeded except as provided for in Appendix B. Appendix B also contains other details regarding the valuation of particular types of assets.

3.12 When determining MEA there are indicators that can be used to determine what asset to select for costing. Such indicators include:

(a) number of faults/100km of line/year
(b) voltage complaints/100km of line/year
(c) proven reliability of the technology
(d) functional compliance with modern operating requirements
(e) meeting statutory and industry safety requirements
(f) least lifetime costs (taking account of all aspects of performance e.g. losses)

3.13 When the tables in Appendix B do not provide guidance on how to value particular major assets such as switchgear, valuers should obtain cost estimates from manufacturers or suppliers. Valuers should explicitly identify in the valuation report each asset which does not fall within Appendix B, together with the replacement cost and the total life assumptions which have been used.

3.14 Any construction cost estimates should be based on knowledge of the work involved, and on efficient industry practice with competitive costs such as would be charged by private contractors.

3.15 Any grants or contributions that have been received should be ignored as it is the deprival value of the assets that is required, not the actual investment.

3.16 Aggregation of the RCs for all the system fixed assets will produce the network RC as required by regulation 20.

Valuation of the System Fixed Assets at Depreciated Replacement Cost (DRC)

Approach to Depreciation

3.17 Asset replacement costs should be depreciated when the existing asset's remaining service life is less than the total life (TL) that would normally be expected from a new asset. The depreciation effectively recognises the limited Remaining Life (RL). The MEA costs should be depreciated according to the RLs of the existing assets.

3.18 The straight line method of depreciation should be used such that the Depreciated Value (DV) is determined as:

DV = UDV x RL/TL

where: UDV = Undepreciated Value (i.e. Replacement Cost (RC))
RL = Remaining life
TL = Total Life.

It is clear from the above that both the Total Life and the Remaining Life need to be established for all assets.

Determining Asset Total Lives

3.19 The maximum TLs of Modern Equivalent Assets (MEA) are set out in the tables in Appendix B. These maxima are not to be exceeded except as provided for in the appendix. The appendix also contains other details regarding the TLs to be used for particular types of assets.

3.20 TLs lower than the specified maxima may be used and may be appropriate in certain circumstances, such as specified in Appendix B.

Determining Asset Remaining Lives

3.21 The life of each asset commences when the equipment is commissioned. The basic procedure for determining RLs is to subtract the age of assets from their TLs.

3.22 The age of assets should be determined for initial ODV valuations, either from records establishing the age, or where necessary from engineering assessments of the age.

3.23 In cases where engineering assessments of the age have been carried out for one valuation, the age in successive valuations should also be based on that earlier engineering assessment – reassessments of the time of installation of the asset are not allowable unless clearly documented historical evidence can be presented to the valuer.

3.24 In cases where materiality of the value of assets is not an issue, and where data availability and calculation complexity would not warrant the determination of age and RL of individual assets, grouping of assets and the assessment of weighted average RLs is acceptable.

3.25 When an asset may be retired early from service because it may become redundant as part of a development of the system, this should not be taken into account in assessing the RL of that asset. However, when a class of assets is routinely replaced as part of the evolution of the system before its technical life expires, then this should be taken into account in assessing the TL for that class of assets.

Refurbishment

3.26 Appendix B provides procedures for assigning RLs in cases where assets have been refurbished.

Fully Depreciated Assets

3.27 In some cases assets which have not been refurbished may still be in service at the end of their TL. In such cases the asset will have been fully depreciated over its life, but may have a Net Realisable Value (NRV) equal to its scrap value after costs of disposal. The value of such assets is their NRV. Generally the NRV of ELB system fixed assets, once the cost of disposal is netted off, is low and can be set aside as not of material value.

Determining the Depreciated Replacement Cost (DRC)

3.28 Aggregation of the DVs (and any NRVs) for all the system fixed assets will produce the network DRC as required by regulation 20.

Optimisation: Valuation of the System Fixed Assets at Optimised Depreciated Replacement Cost (ODRC)

Introduction

3.29 Optimisation should be undertaken only after the RC and the DRC of the existing network asset base have been calculated.

3.30 Optimisation of the ELB's system fixed assets must be carried out to ensure that only assets (or elements thereof) that would be required and fully used in an optimised design of the network are valued. The resulting ODRC valuation should be based on an optimal, modern efficient design that:

(a) provides a quality of supply similar to that which currently exists and which does not exceed the ELB's standard quality of supply criteria;

(b) has sufficient capacity to meet existing demand and, where appropriate, allowed future load growth; and

(c) is depreciated to the same degree as the existing assets.

3.31 Optimisation consists of three stages:

(a) identifying stranded assets;

(b) optimising the system configuration; and

(c) optimising elements in the system.

3.32 The determination of the MEA that would replace existing individual network components is NOT part of the optimisation process. This must be done prior to calculating the RC and, for most network components, has already been taken into account in the maximum replacement costs given in Appendix B.

Constraints on Optimisation

3.33 The optimisation must be carried out subject to the following constraints:

(a) the optimised network must not exceed the existing level of supply security and no part of the network may exceed the ELB's disclosed quality of supply criteria unless non-standard contracts with customers exist that guarantee an enhanced quality of supply;

(b) the location of points of connection to other networks should be assumed to be fixed. However, where a point of connection can be by-passed and this allows a reduction in the replacement value of ELB assets, then that point of connection must be deleted for valuation purposes;

(c) the location and number of existing customers should be assumed fixed; and

(d) the existing boundaries of the ELB should be assumed fixed.

The Process of Optimisation

3.34 Optimisation of the network should be undertaken on a systematic basis. The optimisation process must ensure that all excess capacity that will materially affect the replacement value of the network is optimised out. Optimisation must be undertaken systematically on the following parts of the network:

(a) points of connection to other networks;

(b) zone substations;

(c) subtransmission lines;

(d) each individual high voltage distribution feeder. For the purposes of these rules a feeder includes the distribution network supplied by a single high voltage connection to a distribution substation or to a high voltage switching station, under normal operating conditions; and

(e) the low voltage distribution system;

(f) stores and spares.

Future Load Growth

3.35 The maximum capacity of any part of the optimised network shall be determined by the forecast load growth at the end of the relevant planning period. However, in no case shall optimised capacity exceed existing capacity.

3.36 In order to assure compliance with paragraph 3.35, ELBs must disclose, in the valuation report, both existing loads and the load growth forecast used as a basis for optimisation. As a minimum, existing and forecast loads must be provided for each point of connection, each zone substation and each distribution feeder. Clear justification and a detailed derivation of the load growth forecasts are required. Both the existing maximum demand, and the forecast maximum demand at the end of the planning period, are required. Allowances should be made, where possible, for different growth rates in different parts of the network. Existing loads may be estimated where metering is not available.

3.37 The planning periods over which future load growth can be allowed for shall not exceed the following:

(a) for transmission networks (being networks with a voltage above 33 kV) and points of connection to a transmission network, 10 years;

(b) for sub transmission networks and zone substations, 10 years;

(c) for HV and LV distribution, and other network assets 5 years; and

(d) for distribution transformers no future load growth is permitted. Distribution transformers must be optimised in terms of capacity utilisation, based on current network loadings.

Quality of Supply

3.38 The optimised network must be designed to supply the existing load, and allowed load growth, with a quality of supply that matches the level that currently exists for each part of the network except where this is greater than the disclosed quality of supply criteria.

3.39 An ELB is required to disclose, in its valuation report, the quality of supply criteria that it currently uses as a basis for network design. This should be based on the ELB's analysis of customer requirements and its assessment of network maintenance requirements and costs.

3.40 Relevant quality of supply standards include:

(a) the degree of security (redundancy) in different circumstances or localities;

(b) target reliability indices for different areas of the network (CBD, urban, rural);

(c) voltage regulation criteria;

(d) levels of electrical losses.

3.41 The degree of security shall be disclosed by reference to the level of in-built redundancy, i.e. as (n) or (n-1) or (n-2) or greater component redundancy. (An (n) security level implies no component redundancy so that if a component fails, then customer supply is lost. An (n-1) security level is one in which customer supply is not interrupted in the event of any single component outage etc.) It is recognised that some ELBs are now analysing the degree of security on a probabilistic, rather than a deterministic basis. However, it is nevertheless necessary for an ELB to express its degree of security criteria in such a way that the optimisation process is transparent and can be shown to have been applied consistently across all parts of the network.

3.42 For distribution ELBs, the level of security used as a basis for optimisation shall not be greater than (n-1). Furthermore, an ELB's disclosed quality of supply criteria shall provide for a maximum load, and allowed future load growth on any urban feeder which is normally operated in a closed loop with another feeder of not less than 50% of the optimised feeder rating. In the case of an urban feeder normally operated in a radial configuration the quality of supply shall provide for a maximum load and allowed future load growth under normal operating conditions of not less than 67% of the optimised feeder rating. An urban feeder is one that has a load density greater than 300 kVA per km. A higher level of security is permitted where a specific customer non-standard contract exists or where the network supplies a CBD area. In such cases the higher level of security used as the basis for optimisation must be disclosed in the valuation report.

3.43 In the case of Transpower, account should be taken of prudent standards and practices followed in overseas countries, such as those adopted in Australia and the United Kingdom, relevant decisions of the Grid Security Committee (GSC) and the contractual relationship between Transpower and its connected customers.

3.44 Existing assets that provide a quality of supply greater than that disclosed by the ELB must be optimised out, except where the assets are required in order to meet the ELB's contractual obligations to provide an improved level of security to specific customers.

Identifying Stranded Assets

3.45 Any system fixed assets that are not required to supply line services to customers should be identified and excluded from the optimised network. Such assets are known as Stranded Assets.

Optimising the System Configuration

3.46 Optimisation of system configuration should be carried out in conjunction with the ELB's Planning Engineer or other suitably qualified person. A good current knowledge of electrical system planning is required as optimisation is concerned with the redesign of the system configuration, where the existing configuration exceeds the disclosed optimisation criteria, and not just with the replacement of individual components.

3.47 Optimisation of system configuration must be carried out by considering alternative configurations subject to the constraints on optimisation and in accordance with the relevant criteria relating to the quality of supply declared by the ELB. The optimised configuration is the one that satisfies the relevant optimisation criteria at minimum overall replacement cost.

3.48 In optimising the configuration of the high voltage distribution system, the routes of existing distribution lines should be considered to be fixed, provided they are still required to give supply to existing customers. However assets over and above those required to meet the disclosed quality of supply criteria must be optimised out.

3.49 In the process of optimising the system configuration, certain assets or groups of assets may become excess to requirements and should be valued at nil, while other new assets may need to be notionally brought in. Issues with the optimisation of the system configuration for ELBs are set out in Appendix C.

Optimising Elements in the System

3.50 After the configuration of the system has been optimised, the elements within it must be optimised by considering whether lower capacity elements with a lower replacement cost would be adequate. When optimising the elements within the system the ELB must individually consider all high voltage distribution feeders and the material assets within them. Issues with the optimisation of the system elements for ELBs are set out in Appendix C.

Optimising Network Equipment Spares

3.51 Network equipment spares may be included in the ODV as long as the spares are the same as assets installed in the network. Further, the quantity of the spares to be valued in the ODV must not exceed a reasonable quantity required to meet the ELB’s disclosed quality of supply criteria.

3.52 Stranded assets may be valued as network spares, subject to the criteria set out in paragraph 3.51.

Determining the Optimised Depreciated Replacement Cost (ODRC)

3.53 Once the optimised system has been determined those parts of the optimised network that are different from the existing network must be re-evaluated. This entails applying the cost of the modern equivalent assets as set out in Appendix B and ensuring that these are depreciated to reflect the service potential of the existing assets.

3.54 Stranded assets that are not required as network equipment spares, shall be assigned zero value for the purposes of ODV. It is permissible to assign the NRV of such stranded assets to the "other businesses" owned by the ELB. This is consistent with the Avoidable Cost Allocation Methodology (ACAM) rules. Since stranded assets are avoidable by the ELB, NRVs associated with their disposal should not be assigned to the system fixed assets.

3.55 When assets are notionally brought into the system through optimisation they should be valued at their replacement cost, with reference to the costs in the Appendix B tables.

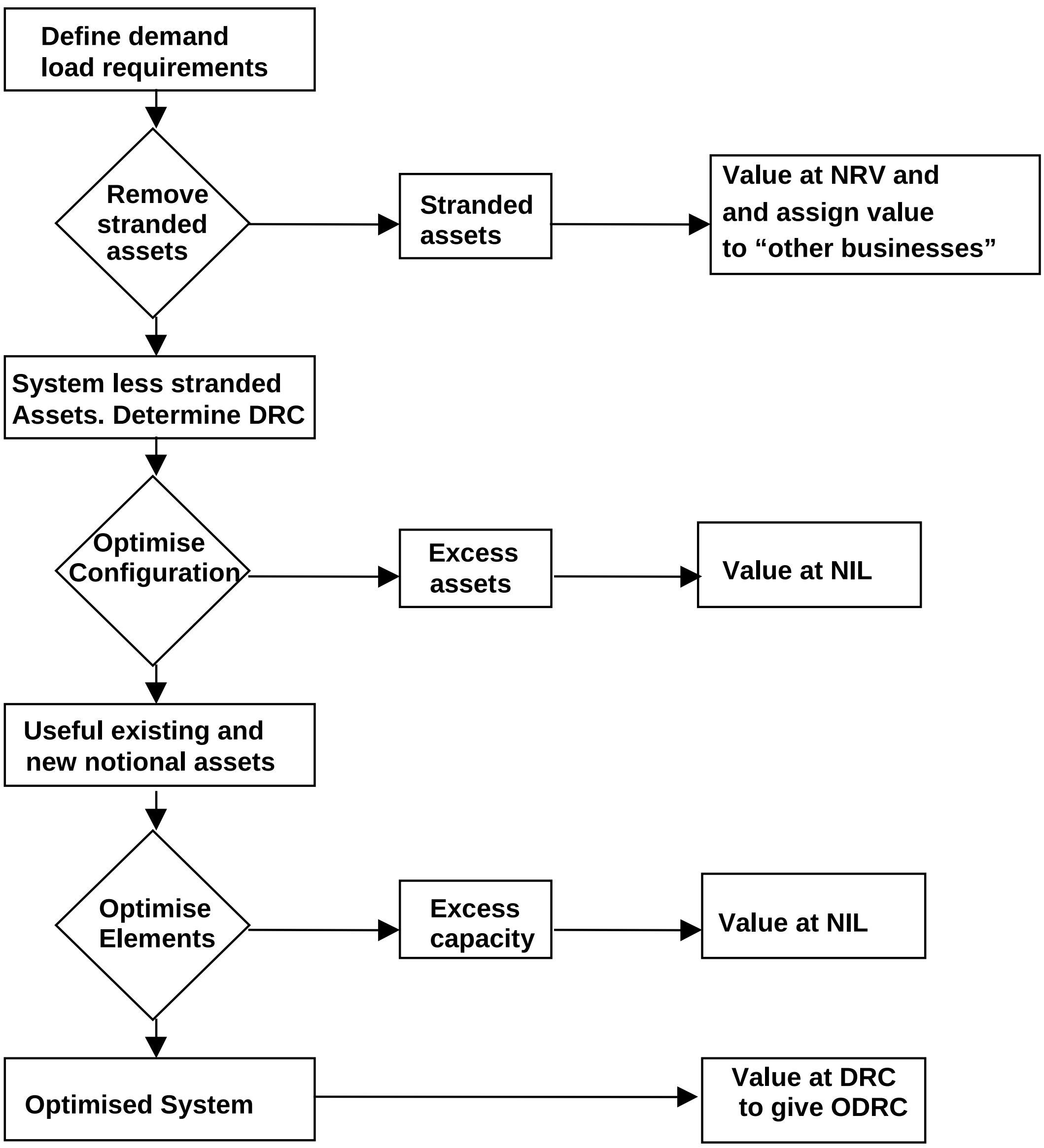
3.56 When optimisation leads to existing assets being notionally replaced, the replacement asset shall be depreciated for the same proportion of its TL as the existing asset was depreciated. When the optimisation involves groups of assets being re-configured, the replacement assets shall be depreciated as a group to reflect the RL of the existing group as a proportion of that group's TL, this being calculated on a weighted average basis.

3.57 Aggregation of the ODRCs of the fixed assets in the optimised system will produce the network ODRC as required by regulation 20. In addition, for those assets where optimisation has occurred, it will be possible to record both the DRC and the ODRC, as also required by regulation 20.

Summary of the Optimisation Process

3.58 Figure 3.1 summarises the steps that should be taken in carrying out optimisation and shows how they fit together.

Figure 3.1: System Optimisation



Valuation Of The System Fixed Assets At Economic Value (EV)

Introduction

3.59 It is necessary to identify the assets on the network that cannot earn a commercially appropriate rate of return (WACC) on their ODRC value. Such assets must be valued at EV and not ODRC. Earnings from such assets may be constrained because the profit maximising revenue that they could generate is insufficient to cover all cash costs and still allow an appropriate return to be made on the ODRC of the assets. Thus, if the EV of an asset is less than its ODRC, the ODV of the asset is its EV.

3.60 The process for determining which assets should have EV values, what those values should be, and the final network ODV, has the following steps:

(a) identifying the segments for EV testing;

(b) determining the profit maximising line tariffs for consumers on the segments to be tested;

(c) calculating the EV based on these profit maximising line tariffs; and

(d) where the EV of the assets in a segment is less than the ODRC of the assets, valuing the assets at EV.

Definition of Segments for EV Testing

3.61 Segments are to be defined by reference to feeders and spurs (for local ELBs) and points of supply (for Transpower).

3.62 ***Feeder:*** For the purposes of these rules, a feeder includes the distribution network supplied by a single high voltage connection to a distribution substation or to a high voltage switching station, under normal operating conditions. That is, feeders are separated from each other by switches that are normally open and which are only closed during fault conditions. For the purposes of EV analysis, the incremental substation assets associated with a particular feeder are included. The spurs radiating from feeders are part of the feeder.

3.63 ***Spur:*** For the purposes of these rules, a spur is defined as a section of a feeder where there is only one route for the supply of electricity. That is, if supply is interrupted on a section of a spur, supply cannot be restored to points downstream of the interruption via an alternate route. Generally, spurs will occur at the outer extremes of a network, but there may be instances of spurs occurring within the interior of the ‘meshed’ network.

3.64 ***Point of Supply*** (Transpower)***:*** For the purposes of these rules, a point of supply is defined as any point where the transmission network is connected to a network or facility owned by any party other than the transmission owner. Such points are commonly referred to as grid exit points (GXPs).

3.65 Segmentation on the basis of tariffs or tariff areas is not permitted.

Identifying the Segments for EV Testing

3.66 It should not be necessary to test all the segments to see whether an EV valuation might be appropriate. Those parts of the network that are least likely to be economic should be delineated by segment from the rest of the network.

General Criteria

3.67 Some of the characteristics of parts of a network that are least likely to be economic are:

(a) Other parts of the network have limited dependence on the segment. This means that the segment is not required for:

(i) delivery of electricity to customers in other parts of the network; and/or
(ii) reliability, availability and security (e.g. back-up delivery)for customers in other parts of the network.

(b) The segment is likely to have a relatively high cost of supply, relative to other parts of the network. High cost segments may:

(i) have low customer density; and/or
(ii) have low load usage relative to capacity;
(This may be the case now or it may be anticipated in the future. For example, where large customers are lost due to industry rationalisation, closures or relocation, where bypass has occurred, or where large feeder lines have been installed in anticipation of future loads which have not occurred); and/or
(iii) be at a remote part of the network.

(c) The prices that can be charged on the segment are likely to be relatively low because of the:

(i) availability of low cost substitute fuels; and/or
(ii) opportunity for low cost by-pass, or occurrence of actual by-pass, of the segment; and/or
(iii) risk of customer disconnection; and/or
(iv) constraints imposed by existing contract conditions.

3.68 Segments that should be identified for EV tests may have any number or combination of these characteristics. These are most likely to occur in semi-rural or rural areas. It is not expected that feeders in urban areas will have these characteristics.

3.69 If those parts of the network that are least likely to be economic prove in practice to be uneconomic, then the next tier of segments must be identified and tested. This process must be repeated until uneconomic segments are no longer found.

Specific Criteria

3.70 The following are specific criteria for identifying segments where the EV of the segment must be calculated for all ELBs. The process follows a sequence whereby the evaluation starts with the feeders, then the spurs off the feeders.

Feeders

(a) The EV of a feeder must be calculated if there is an average of 3.0 ICPs or less per km and an average of less than 20 kVA installed capacity per ICP over the length of the feeder, including its spurs.

(b) If the EV of the feeder, including its spurs, is less than its ODRC, the feeder, including its spurs, must be valued at its EV. In these circumstances, the spurs off that feeder do not have to be evaluated separately.

(c) Where the number of feeders, valued at EV, emanating from a substation is sufficiently large so that the substation should be valued at its EV; the analysis must be extended further into the network. This will involve analysis of the feeder(s) supplying the substation and by iteration may require the EV analysis to be extended to zone substations and grid exit points.

Spurs

(a) The EV of a spur must be calculated if there is an average of 3.0 ICPs or less per km and an average of less than 20 kVA installed capacity per ICP over the length of the spur, including any branch spurs.

(b) If the EV of the spur, including its branches, is less than its ODRC, the spur, including its branches, must be valued at its EV.

Points of supply (Transpower)

(a) An EV analysis must be performed on all points of supply which have been:

(i) subject to submissions regarding ‘excessive costs’ and possibility of by-pass; or
(ii) otherwise identified as ‘high cost’; or
(iii) identified as in a revenue constrained situation.

(b) An EV analysis must be performed on the HVDC link.

3.71 It should be noted that feeders and spurs, where minimum criteria do not hold, might still have uneconomic sections. It is not practical to specify a rule to cover all circumstances and so the above rules are minimum criteria. Line owners are encouraged to perform a more rigorous analysis of their network.

Determining the Profit Maximising Tariffs

3.72 Having identified the segments for which EV must be calculated, the next step is to determine the profit maximising revenue that could be earned from each segment. The revenue that could be earned must be based on the (long run) profit maximising tariffs that could potentially be charged. If actual tariffs or tariffs less than the (long run) profit maximising tariffs are used, then the EV for those segments may be understated. Where this results in an EV less than ODRC it will result in an understatement of ODV.

3.73 The profit maximising line tariff is the tariff that would maximise the ELB's profit derived from a segment of assets. By definition, the profit maximising tariff can be no greater than the maximum sustainable tariff, because at any tariff higher than the maximum sustainable tariff consumers would disconnect, and profits from these consumers would fall to zero.

3.74 In determining profit maximising tariffs, a range of alternative sources of energy should be considered including:

(a) disconnection from the network and electricity supply from a local generator;
(b) substitution of all or part of the electricity supply with other fuels; and
(c) for local ELBs, direct supply from the transmission grid or from a neighbouring ELB.

3.75 When assessing the profit maximising line tariff, care is needed to ensure that the comparison of using the network with the costs of alternatives is carried out correctly – it should be carried out on a delivered energy cost basis. Thus the network maximum unitised line charge, as set by an alternative, is the full unitised cost of the alternative less the unit energy charge when using the network.

Maximum Values

3.76 The following constraints are imposed on the profit maximising line tariff that may be used for EV:

(a) The profit maximising line tariff must not exceed 30¢/kWh for local ELBs (this tariff excludes energy costs but includes transmission costs).

(b) The profit maximising line tariff for Transpower must not exceed 6¢/kWh.

Calculating the EV of a Segment

3.77 The economic value ("EV") of the system fixed assets in a segment of the network is the maximum of the net realisable value of these assets and the present value of the after-tax cashflows attributable to that segment, less any initial investment in non-system fixed assets and working capital. Thus the economic value of the system fixed assets in a segment of the network is:

$$EV = \max(PV(ATCF) - NSFA - WC, NRV)$$

3.78 The EV test should be calculated by applying an avoidable (incremental) cost allocation methodology (ACAM). Under ACAM each segment is treated as "incremental" to the rest of the network (including other segments, which are tested separately). The rest of the network is treated as the "stand-alone" business.

3.79 The avoidable cost allocation methodology makes an assessment of the expenses, revenues, assets, and liabilities that would be avoided by the line owner if it did not operate its "incremental" (the segment) business. These components are allocated to the segment. Revenue is adjusted from its actual level to its profit maximising level.

Net Realisable Value

3.80 The NRV of an asset is its value in its best alternative use. This is commonly viewed as the scrap value of the asset and is the proceeds, less the costs, of realisation. If the NRV of an asset exceeds the present value of the cashflows that can be obtained from the asset, then the economic value of the asset is its NRV.

3.81 Section 62 of the Electricity Act 1992 requires existing consumer connections to be maintained until 31 March 2013, unless consumers agree to disconnection. Therefore, the EV of the assets in a segment can only be valued at their NRV if the consumers connected to those assets have agreed to disconnection. If disconnection has occurred these assets are effectively stranded.

Present Value of the After-Tax Cashflows and Initial Investments

3.82 The components of the present value of the after-tax cashflows and initial investments are:

- the after-tax operating cashflows;
- less any capital expenditure on the segment;
- plus the proceeds from any disposals of assets from the segment;
- less any increase in working capital;
- plus the estimated economic value of the system and non-system fixed assets and working capital at the end of the period of analysis;
- less any initial investment in non-system fixed assets; and
- less any initial investment in working capital.

That is, the principal PV equation is:

$$PV = \sum_{t=1}^{t=k} \frac{ATOCF_t - CapEx_t + Disposals_t - \Delta WC_t + EV_k + NSFA_k + WC_k}{(1+WACC)^t} - NSFA - WC \quad (1)$$

Where:

- *PV* is the economic value today (i.e. at time $t = 0$) of the system fixed assets in the segment;
- *ATOCF* is the expected or forecast after-tax operating cashflows and equals *(revenue - operating expense) – tax(revenue – operating expense - depreciation)*;

- *CapEx* is expected new capital expenditure on the network segment;
- *Disposals* are the expected after-tax proceeds of asset sales or disposals;
- ΔWC is the expected change in working capital over time[1];
- EV_k is the expected economic value at time $t = k$ of the system fixed assets in the segment;
- $NSFA_k$ is the non-system fixed assets at time $t = k$ that are incremental to the network segment;
- WC_k is the working capital at time $t = k$ that is incremental to the network segment;
- *NSFA* is the opening non-system fixed assets that are incremental to the network segment;
- *WC* is the opening working capital that is incremental to the network segment;
- *WACC* is the weighted average cost of capital; and
- *k* is the period of analysis for the segment being valued (i.e. from $t = 1$ to k);
- the subscript *t* is time, and this allows the EV to be calculated for any expected life of the segment.

<u>Components of the Present Value Calculation</u>

Revenue

3.83 This item consists of all revenue from the profit maximising line tariffs that could be derived from the consumers on the segment. This revenue does not include any interest income. This revenue is not to be based on current line tariffs unless these are demonstrably the profit maximising line tariffs, nor should the revenue be graduated from current to profit maximising line tariffs levels.

3.84 Revenue may be adjusted for future load growth, which can occur through the increased consumption of existing consumers or the addition of new consumers. Any adjustments for future load growth must comply with the rules in paragraphs 3.36 and 3.37.

3.85 Capital contributions are generally regarded as revenue and taxable income and so should be included in the segment's revenue. If capital contributions are included they must not be offset or deducted from the related capital expenditure.

Operating Expenditure

3.86 Operating expenditure only includes the cash operating expenses that are directly related (incremental) to the segment of network being valued. Operating expenditure does not include any expenditure that cannot be specifically linked to the segment, or expenditure that could not be avoided if the segment was removed from the network. Operating expenditure does not include:

- depreciation, as this is not a cash expense;
- any amortisation of any intangibles, as these are not cash expenses;
- interest expense (this is not an operating expense – it is a cost of funding).

[1] ΔWC will be negative if working capital is expected to decrease.

Depreciation

3.87 Depreciation is included in the analysis because of its tax effect. The depreciation expense must be that allowed for taxation purposes. This will differ from that based on ODV where the tax and ODV asset values and their tax depreciation and economic lives differ.

Tax

3.88 The after-tax operating cashflows are specified as:

ATOCF = (revenue - operating expense)
– tax(revenue – operating expense - depreciation)

3.89 If the revenue from a segment is insufficient to offset the cash operating expenses plus the tax depreciation expense, a tax loss will be attributable to the segment. Assuming any tax loss can be used to reduce taxable income derived elsewhere on the network, the tax loss represents a positive cashflow as it reduces tax payments. The amount of the reduction in tax payments equals the tax loss multiplied by the tax rate. Mathematically:

if revenue < operating expense + depreciation

then the tax loss = revenue - operating expense – depreciation

and

the reduction in tax payments = - tax(revenue - operating expense – depreciation)

3.90 That is, the reduction in tax payments is a positive cashflow on the assumption that these losses can be used to offset income elsewhere. Thus the specification of after-tax operating cashflows above, correctly treats the economic impact of tax losses without any further adjustment.

3.91 The tax rate must be the corporate tax rate applying in New Zealand.

Capital Expenditure

3.92 Capital expenditure includes all cash outlays on the segment that are not classified as operating expenditure. It includes capitalised replacements of assets and extensions to the segment.

Disposals

3.93 Disposals refer to the after-tax proceeds (if any) from the removal and sale of any assets on the segment. It includes the ODRC of any assets transferred to spares (note that if such transfers result in an excess of spares, the ODRC is zero). Disposals may have a negative value.

Working Capital

3.94 The working capital items are those associated with the segment. They include accounts receivable attributable to consumers on the segment and accounts payable associated with operating expenses incurred on the segment. Changes in these working capital items should be included to correctly represent actual cashflows. For example, an increase in accounts receivable (which increases working capital) means that less cash was actually received in the period than indicated by the revenue figures. As such there has been an investment of capital and this should therefore be treated as a cash outflow.

3.95 For the purposes of calculating the EV of a segment, it may be reasonable to assume that in periods of low inflation, and no growth in electricity demand and consumer numbers, that changes in working capital items will be zero. In these circumstances, the term ΔWC_t in equation (1) is zero.

Non-System Fixed Assets

3.96 These are the fixed assets for which the valuation is not covered by this handbook and that are directly related (incremental) to the segment of network being valued. The allocation of non-system fixed assets to the segment does not include any items that cannot be specifically linked to the segment, or items that could not be avoided, if the segment was removed from the network.

Discount Rate

3.97 The after-tax weighted-average cost of capital (WACC) is used as the discount rate. In most cases the WACC for the segment will be the same as the WACC for the line business overall.

3.98 The EV must be calculated on an after-tax basis. Although it is theoretically possible to perform the analysis on a pre-tax basis, in practice it is very difficult to derive the correct pre-tax discount rate. One cannot normally gross up the after-tax discount rate to a pre-tax rate and discount the pre-tax cashflows.

Simplifications to the General Model and Equation (1) for a Segment to be maintained in Perpetuity

3.99 The following section simplifies equation (1) where the segment is intended to remain in operation in perpetuity and certain assumptions can be reasonably made. Note that the present value of EV_k, $NSFA_k$ *and* WC_k is effectively zero in these circumstances as the period analysed is perpetual.

Assumption 1: Changes in working capital are zero. This may be a reasonable assumption in periods of low inflation and little or no change in the expected growth of the network segment.

Assumption 2: The expected after-tax operating profits are constant in each period[2]. Thus the expected after-tax operating cashflows can be re-expressed as:

ATOCF = (revenue - operating expense- depreciation)
– tax(revenue – operating expense – depreciation) + depreciation

= NOPAT + depreciation

where: *NOPAT* is the expected net operating profit after-tax and is calculated by including depreciation for taxation purposes as a deductible expense[3].

Assumption 3: Expected capital expenditure on the segment will occur uniformly through time and offsets expected depreciation and disposals of the assets on the segment. The capital expenditure should be sufficient to maintain the operating assets of the network segment in perpetuity. Thus, the after-tax cashflows ("*ATCF*") are:

ATCF = NOPAT + depreciation- CapEx + Disposals

= NOPAT

Equation (1) can now be written as:

$$PV = \sum_{t=1}^{t=\infty} \frac{NOPAT_t}{(1+WACC)^t} - NSFA - WC \qquad (2)$$

When expected *NOPAT* is assumed constant over time (i.e. assumption 2), equation (2) can be re-expressed as:

$$PV = \frac{NOPAT}{WACC} - NSFA - WC \qquad (3)$$

A Simple EV Test

3.100 The above analysis (equation (3)) yields a simple test to determine whether or not the assets in a segment that is to be maintained in perpetuity, should be valued at ODRC or EV:

if NOPAT < WACC x *(ODRC + NSFA + WC)*

then ODV = EV, otherwise ODV = ODRC.

[2] It is also implicitly assumed that expected tax depreciation on fixed assets is constant over time.
[3] In calculating *NOPAT* interest expense is excluded from operating expenses.

Minimum Acceptable EV Method

3.101 The simple EV test specified in paragraph 3.98 is the minimum acceptable method to be used in calculating the economic value of the assets comprising a segment of the network. More detailed approaches that relax some or all of the specified assumptions may be used, but if such alternate approaches are used, the valuer must be satisfied that the alternate approach will produce a more accurate result. However, whatever approach is used, the EV must be calculated on an after-tax basis.

3.102 The EV methodology used to test segments must be disclosed in the ODV report.

Determining the Network ODV

3.103 Aggregation of the values, whether ODRC or EV, of the network assets will produce the value of the network system fixed assets at ODV as required by regulation 20.

APPENDIX A: ASSET TYPES, GROUPS AND SUBGROUPS FOR LINE BUSINESSES

Asset registers should include, as a minimum, the classification of assets as set out in this appendix.

TRANSPOWER

(a) AC Transmission Lines

Transmission lines should be divided into subgroups by voltage: e.g. 50kV, 66kV, 110kV and 220kV.

Further subdivision should be by conductor size.

For standard valuation purposes the unit is 1km.

(b) Benmore-Haywards HVDC Link

The Benmore-Haywards HVDC link including land and buildings should be recorded.

(c) AC Substation Equipment

Substations should be divided into subgroups as follows:

Category	Average No. of Incoming HV bays
Major	14
Medium	8
Small	6
Rural	2

TRANSPOWER and LOCAL ELBs

(d) Subtransmission

Subtransmission Lines

Subtransmission lines should be divided into subgroups by voltage: e.g. 11kV, 22kV, 33kV.

Further subdivision should be by conductor size (e.g. 185mm^2 aluminium, 100mm^2 aluminium).

For standard valuation purposes the unit is 1km.

Subtransmission Cables

Subtransmission cables should be divided into subgroups by voltage e.g. 11kV, 22kV, 33kV. If cable sizes differ markedly within an ELB, the quantities should be recorded separately for ranges of capacity.

For standard valuation purposes the unit is 1 km.

(e) Zone Substations

Zone substations should be divided into subgroups by capacity: 0-5MVA, 6-10MVA, 11-20 MVA, 21-30MVA, over 30MVA.

Numbers of substations should be determined separately for the asset categories identified in Table B.1 of Appendix B.

Equipment owned at associated points of supply should be listed under this section e.g. circuit breakers, metering and communications equipment.

Ripple injection equipment should be included under this class of asset and will incorporate control equipment, tuned circuit, coupling equipment and remote units. The master station should be included separately with the system control facilities.

For standard valuation purposes the unit is one substation.

(f) Distribution Lines and Cables

Distribution Lines

Distribution lines should be divided into subgroups by voltage, conductor size ranges and type:

- (i) 6.6kV, 11kV and 22kV
- (ii) (150mm^2 to 300mm^2 Al incl) etc aluminum or equivalent
- (iii) 3 phase, single phase, SWER
- (iv) lines with more than one voltage.

For standard valuation purposes the unit is 1 km.

Distribution Cables

Distribution cables should be divided into subtypes by voltage: 6.6kV, 11kV and 22kV.

If necessary, they should also be divided by conductor size.

For standard valuation purposes the unit is 1km.

(g) Distribution Switchgear

Distribution switchgear should be divided into subgroups by type. Voltage regulators are to be included in this group.

(h) Distribution Substations

Distribution substations should be divided into subgroups: pole mounted, ground mounted (covered), indoor (kiosk) or on customers' premises.

Consumer substations with the substation sited in a customer's premises should be treated as a subgroup.

For standard valuation purposes the unit is one substation.

(i) Distribution Transformers

Distribution transformers should be divided into subgroups by size.

For standard valuation purposes the unit is one transformer.

(j) Reticulation

Low Voltage Lines

It should not be necessary to divide low voltage lines into subgroups by conductor size or according to whether there are one, two or three phases. However, the lines should be divided into subgroups by type: overhead and underbuilt. Streetlighting mains, should be recorded separately.

For standard valuation purposes the unit is 1km.

Low Voltage Cables

It should not be necessary to divide low voltage cables into subgroups by conductor size, Streetlighting mains, should be recorded separately.

For standard valuation purposes the unit is 1km.

(k) Customer Service Connections Excluding Meters and Relays

This class of asset includes cable or line connections from the mains to the property boundaries and includes LV fuses. The assets should be divided into subgroups according to whether they are for one or three phases.

For standard valuation purposes the unit is 1 service.

(l) System Control Facilities

Most local ELBs have only one system control centre which, along with any other system control facilities, should be recorded separately as a master station. Remote units should be recorded with the appropriate zone substation.

(m) Communication Facilities

This class of asset comprises:

(i) terminal facilities: these should be recorded as a group with the master station and the remote units recorded with the zone substation.

For standard valuation purposes the unit is one terminal.

(ii) lines/cables: these should be subgrouped if necessary.

For standard valuation purposes the unit is 1km.

(n) Miscellaneous Equipment

This class of asset includes items such as air break switches and auto reclosers.

(o) Stores and Spares

The stock of stores and spares should be recorded.

(p) Land

Land owned by ELBs on which substations are built should be recorded.

(q) Easements

Easements which qualify for assessment (see B.29) should be recorded.

APPENDIX B: VALUING ASSETS AND MAXIMUM ASSET COSTS AND LIVES

B.1 This appendix gives the methodology that should be applied in using replacement costs to value the system fixed assets of ELBs. The appendix also contains Table B.1 (for local ELBs), and Tables B.2–B.8 (for Transpower), which specify the maximum replacement costs and the maximum asset lives that are not to be exceeded for the purpose of assessing the depreciated replacement costs of ELB system fixed assets.

ELB Maximum Costs

B.2 Maximum replacement costs are shown in Table B.1 (for local ELBs), and Tables B.2–B.8 (for Transpower). These values are maxima and for valuation purposes are not to be exceeded.

B.3 The values in the tables are based on installed costs for Modern Equivalent Assets (MEA). They have been based on industry best practice and competitive pricing and include the following elements:

(i) costs of materials delivered to store;

(ii) direct labour including indirect costs (ACC, holiday pay, sick leave, training, supervision, etc);

(iii) transport and plant costs for delivery and erection; and

(iv) on-cost incorporating business administration, design, construction supervision, and project management costs.

The costs of land use consents, easements, compensation are excluded. GST is excluded but other taxes and duties incurred in the construction of the assets are included.

B.4 For equipment used in adverse conditions multipliers can be applied to the values as specified in the tables, but only subject to conditions as specified in B.9, B.14 and B.15. To ensure appropriate application of the cost multipliers, a record of their application should be kept for scrutiny and approval by the Valuer. This information must include:

(i) multiplier used;

(ii) quantity of item to which it is applied

(iii) the specific conditions justifying the use of the multiplier.

B.5 Where the nature of an asset in service differs from any in the tables, an engineering assessment of the replacement cost can be made, subject to the approval of the Valuer. Before such an assessment is made, the Valuer must be satisfied that there is justification for not selecting an MEA listed in the tables. This assessment must be recorded in the valuation report.

B.6 In assessing costs for assets not listed in the tables, or where the Valuer's assessed value is less than the maximum listed cost, the cost elements set out in B.3 should be recorded. Any costs so determined should be based on competitive pricing estimates, and should be commensurate with a significant scale of construction (within the limits of available resources), not piecemeal additions.

ELB Asset Types

B.7 In the following sections additional information is given in relation to the valuation of certain types of asset used by ELBs.

Overhead lines

B.8 **Local ELBs:** The maximum overhead 33kV and 11kV line costs in Table B.1 have been based on three phase construction in a rural environment utilising 70-80m spans. For lines of these voltages in other environments, maximum costs can be established by applying the following multipliers:

overhead line urban	:	1.5 to 1.8 times B.1 cost
overhead line remote area	:	1.0 to 1.25 times B.1 cost
overhead line rugged terrain	:	1.2 to 1.3 times B.1 cost;

where remote areas are those which are situated more than 75 km from the nearest works depot of either the ELB or a line construction contractor; rugged terrain includes those areas where normal line operating vehicles and plant cannot be used and where it is necessary to use helicopters, tracked vehicles or other special plant.

B.9 **Transpower:** The maximum overhead line costs for AC transmission lines in Table B.8 have been based on nominal average span lengths of 165m and 375m for pole and tower lines respectively, in flat rural land with an assumption that the work is carried out 50km from the nearest urban area. There is no adjustment for further remoteness. Costs for overhead lines in Table B.8 in other terrain can be established by applying the following multipliers:

overhead line hilly terrain	:	1.07 times B.8 cost
overhead line mountainous terrain	:	1.23 times B.8 cost
overhead line urban terrain	:	1.20 times B.8 cost

B.10 The maximum costs in Table B.1 for circuits of lower voltage erected on higher voltage lines (i.e. underbuilt) have been based on the marginal cost of additional materials and installation.

B.11 Costs for special configurations (e.g. composite 33kV/11kV/LV lines and aerial bundled conductor construction) and for construction at other voltages (e.g. 110kV, 66kV or 22kV) should be determined by the Valuer in accordance with clause B.6.

Underground Cables

B.12 Underground cables should be valued on the basis of replacement cost with underground cables in determining RC or DRC, but this should be reviewed as part of the optimisation process (see Appendix C).

B.13 The maximum underground cable costs in Table B.1 have been based on laying in an urban area with developed infrastructure.

B.14 Cables laid in business districts require special consideration, and a multiplier of 1.15 or 1.25 times the costs of Table B.1 can be applied. This multiplier takes into account the greater vehicular and pedestrian traffic, restricted access times, special reticulation requirements and areas requiring substantial reinstatement.

B.15 For cables laid in rocky ground a multiplier of 1.5 to 2.0 times the costs of Table B.1 can be applied.

B.16 The Table B.1 cost of double circuit (viz. two) cables including cables of differing voltages laid together incorporates the marginal cost of the extra cable and laying in a joint trench. Where more than two cables of the same voltage are laid together the replacement cost should be determined in accordance with this principle and clause B.6.

B.17 The cost of cables intended to operate at voltages other than 33kV, 11kV, LV and submarine cables should be determined by the Valuer in accordance with clause B.6.

B.18 The standard replacement cost of all 33kV and distribution cables should be based on unarmoured XLPE cables being the deemed MEA. The replacement cost of LV cables should be based on PVC or XLPE unarmoured construction.

Zone Substations

B.19 The replacement costs for zone substations should be based on cost effective configuration with single bus distribution switchgear unless there are compelling reasons for departure from this. The replacement costs should be compiled by the Valuer in accordance with clause B.6 and should be presented in the categories set out in Table B.1 (for local ELBs) and Tables B.2 and B.3 (for Transpower).

B.20 The replacement cost of substation buildings should be included in the substation valuation, but the land value should be treated separately.

Distribution Substations

B.21 Distribution substations should be valued without distribution transformers, and the land value should also be treated separately. The replacement cost of any enclosing structure should, however, be included.

B.22 The replacement cost of pole mounted substations should include the cost of steelwork, extra poles if applicable, LV fuses and earthing. In the case of ground mounted or similar transformer/substation units the relevant cost is the cost of the additional equipment which is added to the transformer excluding distribution switchgear.

Distribution Transformers

B.23 Replacement costs for distribution transformers are given in Table B.1 (for local ELBs) for currently available distribution transformer sizes of New Zealand manufacture. Replacement costs for distribution transformers for Transpower are given in Table B.4. Where other sizes are in service, the cost of the next largest available size should be used for valuation purposes.

Streetlighting Mains

B.24 For valuation purposes the MEA of streetlighting mains can be a photo-electric cell included as an integral part of the lantern where the streetlights are in close proximity to existing LV reticulation. Where LV reticulation is not available, streetlighting mains can be valued as a stand alone 2 core cable.

System Control Facilities

B.25 All system control facilities associated with a system control centre should be valued together as a master station. The value of remote units should be incorporated in the value of the appropriate zone substation.

Communication Facilities

B.26 Terminal facilities should be valued as a master station. The value of remote units should be incorporated in the value of the appropriate zone substation.

Stores and Spares

B.27 Only a reasonable quantity of stores and spares should be valued as part of the system fixed assets (consistent with the Avoidable Cost Allocation Methodology (ACAM) rules). Any excess stores and supplies (including spares for assets no longer in service) should be valued at Net Realisable Value (NRV) and the valuation not included with that of the line business, but with that of ‘other businesses’ owned by the ELB.

Easements

B.28 The “existing works” provisions in the Electricity Act 1992 protect the ownership of lines (both ELBs and Transpower) constructed or commenced prior to January 1993. They also provide for line owner access to the land the works are on, to inspect, maintain and operate them. Under previous legislation the Crown and ESAs had virtually unlimited rights of access to land to build works. Easements were not required. Easements are not explicitly required by the Electricity Act 1992, but are expected to be the normal means of registering rights.

B.29 Only easement rights obtained and registered against a land title after after 1 January 1993, (or in the case of Transpower, additionally between 1 January 1988 and 1 January 1993), and paid for, can be valued provided that the sum paid has not already been expensed.

ELB Maximum Lives

B.30 Maximum asset lives are given in Table B.1 (for local ELBs) and Tables B.2-B.8 (for Transpower). These lives are maxima and are not to be exceeded for the purpose of determining TLs of assets, except as provided for in B.34.

B.31 Where an asset is made up of a number of items that have differing lives, a weighted average life is to be determined. This assessment should be recorded in the valuation report.

B.32 Lives of assets not listed in Table B.1 (for local ELBs) and Tables B.2-B.8 (for Transpower) should be established on a comparable basis with those in the tables. Such lives should not exceed the maximum lives for comparable assets, should be subject to the approval of the Valuer, and should be verified and documented. Assessment of the TL of such assets must include:

(i) examination of asset service records;

(ii) discussion with maintenance personnel; and

(iii) physical inspection.

B.33 TLs less than the maxima of Table B.1 (for local ELBs) and Tables B.2-B8 (for Transpower) should be assigned when the Valuer considers this appropriate. Circumstances when this could be appropriate include:

(i) assets in coastal environments;

(ii) assets subject to particularly high use or high fault levels or showing systematic premature retirement due to failure;

(iii) assets which have been poorly maintained.

TLs so assigned should, however, never be less than 50 percent of the relevant Table B.1 maximum.

B.34 The TL of certain assets, as specified below, may be extended by the Valuer where specified conditions have been satisfactorily met. These are:

zone substation transformers	(clause B.41)
indoor MV or indoor 33kV switchgear	(clause B.42)
distribution transformers	(clause B.43)
transmission lines	(clause B.44)

B.35 In order to justify the extension of TLs as provided in B.34, the following information should be available to the Valuer for scrutiny:

(i) an age profile of the assets in the category concerned, showing the original population, survival population in each year and number of failures in each year, sufficient to demonstrate that the asset category concerned warrants on average the application of life extension; and/or

(ii) information on the standard or specification used in the purchase of the asset or that class of asset sufficient to demonstrate modern or special technology that would warrant the application of a longer life.

B.36 In addition the following information should be available:

(i) a maintenance policy statement indicating the nature, scope and regularity of maintenance work carried out on the asset or class of asset since its installation, sufficient to support the claim for a longer life;

(ii) maintenance and test records of the asset (or, where the life extension relates to a class of asset, representative records for that class of asset) sufficient to demonstrate that the agreed maintenance policies have been applied over the life of the asset; and

(iii) where relevant (e.g. for transformers), information on the loading applied to the asset or class of asset over time, demonstrating circumstances that would warrant a life extension.

Refurbishment

B.37 Refurbishment is classed as work done on the asset (or set of assets) that results in a material extension of its service life beyond its normal TL. This is in distinction to maintenance work which is done to ensure that an asset is able to perform its designated function for its normal TL. Accumulated maintenance should not be considered as refurbishment.

B.38 When an asset has been refurbished, the Valuer should assign an RL, effective from the time of refurbishment, but this RL should not be greater than the maximum TL as specified in Table B.1 (for local ELBs) and Tables B.2-B8 (for Transpower).

Lives for Particular Asset Types

B.39 In the following sections additional information is given in relation to the assessment of lives of certain types of asset.

Overhead Lines

B.40 Two different sets of life maxima are given in Table B.1 – one for concrete poles, the other for wooden poles. This is notwithstanding the fact that a single set of maximum values has been given reflecting the MEA asset replacement type.

Zone Substations

B.41 The maximum TL of zone substation transformers is to be taken as 45 years, as shown in Table B.1. However, in accordance with clauses B.34-B.36, where sound maintenance programmes have been in place over the life of the asset, the TL for such transformers may be extended, but to not more than 60 years. Such an extension assumes a typical urban and commercial load curve and cyclic loading in accordance with IEC 354 and should cover most situations in New Zealand. For such extensions, the Valuer should be provided with all required supporting information.

Indoor distribution switchgear

B.42 The maximum TL of indoor distribution switchgear is to be taken as 45 years, as shown in Table B.1. However, in accordance with clauses B.34-B.36, where indoor distribution switchgear is of modern, sealed design and specified to operate without maintenance for an extended number of operations, the TL may be extended, to not more than 55 years. In such cases, the Valuer should be advised of the type of switchgear installed and the Standard (IEC) to which it has been constructed. The TLs in this clause are also applicable to indoor zone substation incoming (33kV) switchgear. (Normally, however, such switchgear is outdoor.)

Distribution Transformers

B.43 The maximum TL of distribution transformers is to be taken as 45 years, as shown in Table B.1. However, in accordance with clauses B.34-B.36, distribution transformer lives may be extended, but to not more than 55 years, providing that general maintenance, including tank replacement during the life of the transformer, is expensed and not capitalised. The major factor in determining the ultimate life of the transformers is then the life of the core and windings. For the application of an extension to the TL, the Valuer must be provided with all required supporting information.

Transmission Lines

B.44 The maximum TL of transmission lines is to be taken as 55 years, as shown in Table B.8. This is the TL allowed for transmission lines constructed in areas with normal environmental conditions. Transmission lines in coastal (hostile corrosive environment) is to be accorded an asset TL of only 35 years, and, in accordance with clauses B.35 and B.36, transmission lines lives may be extended, but to not more than 70 years, where those transmission lines are in lower than normal corrosive conditions (dry inland).

Valuation of the DC Link

B.45 The HVDC link between Benmore and Haywards is a major component of the transmission system. The HVDC link is an asset whose economic value is based on the service it provides to the New Zealand electricity system. Because of the size of the investment in DC assets it is essential that the economic valuation of this asset is carried out carefully and objectively.

B.46 The High Voltage Direct Current link should be valued using the standard ODV methodology. The factors that should be addressed in the valuation include:

- The economic justification for the link;

- The risk of physical or functional failure of the link; and

- The risk of under-utilisation of the link, either for operational reasons, or due to insufficient generation in the South Island or due to major new load arising in the South Island or additional generation built in the North Island.

- The EV of the link should be assessed in terms of its value to the system. This involves an assessment of what the system costs (i.e. both generation and transmission) would have been in the absence of any link, or with a link of different size or specification level.

Local ELB Maximum Costs and Lives

B.47 The following table gives maximum replacement costs and lives that should be applied in valuing local ELB system fixed assets.

TABLE B.1: LOCAL ELB MAXIMUM ASSET VALUES AND LIVES (1998 TABLE REVISION)

Asset Description	Unit	Notes	Maximum Value ($000) a	Maximum Life (Years)	
				Pole Type	
SUBTRANSMISSION				Concrete	Wood
33 kV Lines – Heavy (≥ 150 mm^2, ≤ 300 mm^2 Al)	km	b	40	60	45
33 kV Lines – Light (< 150 mm^2 Al)	km	b	35	60	45
33 kV Lines – DCct Heavy	km	b	60	60	45
33 kV Lines – DCct Light	km	b	50	60	45
				Cable Type	
				XLPE	PILC
33 kV - Cables (≤ 240 mm^2 Al)	km	c	165	45	70
33 kV - Cables DCct (≤ 240 mm^2 Al)	km	c	265	45	70
Pilot/Communications Ccts O/H	km	b	**	45	
Pilot/Communications Ccts U/G	km	c	**	45	
Air Break Switch	No.	b	8	35	
ZONE SUBSTATIONS					
Land	No.		-	-	
Site Development and Buildings	No.		**	40	
Incoming (Outdoor) Switchgear, Protn. & Controls	No.	d	**	40	
Transformers	No.	e	**	45	
Transformer Protection and Controls	No.		**	40	
Distribution CB, Protection and Controls (Incom/Bus)	No.	d	**	45	
Distribution CB, Protection and Controls (Feeder)	No.	d	**	45	
				Pole Type	
				Concrete	Wood
Outdoor Structure if not included above	No.		**	60	45
SCADA and Communications Equipment	No.		**	15	
Ripple Injection Plant	No.		**	20	
Other Items	No.		**	40	
				Pole Type	
DISTRIBUTION				Concrete	Wood
Lines					
11 kV O/H Heavy (≥ 150 mm^2, ≤ 240 mm^2 Al)	km	b	24	60	45
11 kV O/H Medium (> 50 mm^2 , < 150 mm^2 Al)	km	b	22	60	45
11 kV O/H Light (≤ 50 mm^2 Al)	km	b	20	60	45
11kV single phase or SWER lines	km	b	17	60	45
11 kV O/H DCct Heavy	km	b	34	60	45
11 kV O/H DCct Medium	km	b	31	60	45
11 kV O/H DCct Light	km	b	28	60	45
11 kV O/H Underbuilt Heavy	km	b	10	60	45
11 kV O/H Underbuilt Medium	km	b	9	60	45
11 kV O/H Underbuilt Light	km	b	8	60	45

Asset Description	Unit	Notes	Maximum Value ($000) a	Maximum Life (Years)	
DISTRIBUTION (Continued)				Cable Type	
Cables				XLPE	PILC
11 kV U/G Heavy (> 240 mm^2, ≤ 300 mm^2 Al)	km	c	120	45	70
11 kV U/G Medium(> 50 mm^2, ≤ 240 mm^2 Al)	km	c	90	45	70
11 kV U/G Light (≤ 50 mm^2 Al)	km	c	65	45	70
11 kV U/G DCct Heavy	km	c	170	45	70
11 kV U/G DCct Medium	km	c	135	45	70
DISTRIBUTION SWITCHGEAR					
Disconnector (Excl Pole)	No.		2.3	35	
Load Break Switch (Excl Pole)	No.		5.5	35	
Dropout Fuse 3 Ph (Excl Pole)	No.		1.5	35	
Oil Sw/Sectionaliser (Excl Pole)	No.		17	40	
Recloser (Excl Pole)	No.		20	40	
Circuit Breaker	No.		25	40	
Voltage Regulator	No.		**	55	
Ring Main Unit - 3 Way	No.		15	40	
Extra Oil Switch	No.		5	40	
Extra Fuse Switch	No.		8	40	
DISTRIBUTION TRANSFORMER (kVA)					
Single/Two Phase Units					
10	No.	f, g	2.4	45	
15	No.	f, g	2.5	45	
30	No.	f, g	3.1	45	
50	No.	f, g	4.2	45	
Three Phase Units (Pole Mounted - Bushing Terminations)					
15	No.	f, g	3.3	45	
30	No.	f, g	3.6	45	
50	No.	f, g	4.7	45	
100	No.	f, g	7	45	
200	No.	f, g	11	45	
300	No.	f, g	12.9	45	
500	No.	f, g	18	45	
Three Phase Units (Cable entry, one or both voltages)					
100	No.	f, g	7.5	45	
200	No.	f, g	11.5	45	
300	No.	f, g	13.3	45	
500	No.	f, g	18.5	45	
750	No.	f, g	22	45	
1,000	No.	f, g	24.9	45	
1,250	No.	f, g	33	45	
1,500	No.	f, g	39	45	
DISTRIBUTION SUBSTATIONS					
Pole Mounted (50 kVA or less)	No.	h	0.5	40	
Pole Monted (100 kVA or more)	No.	h	1.8	40	
Ground Mounted (Covered)	No.	i	4	40	
Kiosk (Masonry or block enclosure)	No.	i	9	40	
On Customer’s Premises with Feedout	No.		2	40	

Asset Description	Unit	Notes	Maximum Value ($000) a	Maximum Life (Years)	
				Pole Type	
LV LINES				Concrete	Wood
Overhead - LV only	km	j	38	60	45
Overhead Underbuilt	km	j	12	60	45
				Cable Type	
				XLPE /PVC	PILC
Underground - LV Only	km	j, k	55	45	70
Underground - with MV	km	j, k	25	45	70
CUSTOMER SERVICE CONNECTIONS EXCLUDING METERS AND RELAYS					
LV - 1 ph	No.		0.07	45	
LV - 3 ph	No.		0.18	45	
OTHER SYSTEM FIXED ASSETS					
SCADA and Comms (Central Facilities)	Lot		**	15	

a All values are based on installed costs (excluding GST) for MEA.
b Values relate to costs for rural construction.
c Values are based on costs of underground reticulation for suburban areas in average ground conditions.
d In accordance with clause B.43 (and the requirements of clause B.33), the lives for indoor distribution (or indoor 33kV) switchgear may be extended, to no more than 55 years, if it is of modern, sealed design and specified to operate without maintenance for an extended number of operations.
e In accordance with clause B.42 (and the requirements of clause B.33), of the lives of zone substation transformers may be extended, to no more than 60 years, provided that evidence of a sound maintenance programme is presented to the Valuer.
f Values based on replacement costs are for currently available sizes (NZ manufacture). For intermediate sizes value at next size up. (Optimisation factor should take account of any resulting enhancement.)
g In accordance with clause B.44 (and the requirements of clause B.33), the lives of distribution transformers may be extended, to no more than 55 years, provided that evidence of a sound historical maintenance programme over the life of the asset is presented to the Valuer.
h Excludes dropout fuses.
i Includes enclosure and LV frame. Use kiosk only where additional LV frames required.
j If detailed records of LV quantities are not available, the quantities used in the valuation should be based on an average length of LV for each size of transformer.
k Values are based on costs for suburban subdivisions.
** No maximum value assigned.

Transpower Maximum Costs And Lives

B.48 The following tables give maximum replacement costs and lives that should be applied in valuing Transpower's system fixed assets.

B.49 The maximum replacement costs included in the tables are subject to adjustment for seismic factors (for substations) and interest incurred during construction. The adjustment factors are shown tables B.9 and B.10.

Substations by Standard Size

For valuing establishment and buildings, substations are split into facilities of four standard sizes - Major, Medium, Small and Rural.

Table B.2: Establishment Building Block Costs

Type	Description	Maximum Value ($000)	Maximum Life (years)
Major	accommodating on average 14x220kV, 19x110kV and 15x33kV or 15x11kV bays, roadways, etc	3,184.75	55
Medium	accommodating on average 8x220kV, or 8x110kV and 10x33kV or 10x11kV bays, roadways, etc.	1,203.07	55
Small	accommodating on average 6x110kV and 15x33kV or 15x11kV bays, roadways, etc	1,072.82	55
Rural	accommodating on average 2x66kV, 6x33kV or 6x11 bays, roadways, etc	973.34	55

Substations (Standard sizes) by Indoor/Outdoor

For costing buildings at substations, the four standard sizes are further broken down to differentiate between indoor or outdoor facilities.

Table B. 3: Buildings Building Block Costs

Type	Description summary	Maximum Value ($000)	Maximum Life (years)
Major OD	Facilities associated with outdoor switchyard with on average 14x220kV, 19x110kV and 15x33kV or 15x11kV bays, 155.5msq control room.	175.91	55
Major ID	Facilities associated with outdoor switchyard with on average 14x220kV, 19x110kV bays and indoor switchgear and control facilities with on average 15x33kV or 15x11kV bays with 155.5sqm control room and 201.6sqm switchgear room	365.81	55

Type	Description summary	Maximum Value ($000)	Maximum Life (years)
Medium OD	Facilities associated with outdoor switchyard with on average 8x220kV or 8x110kV and 10x33kV or 10x11kV bays, 103.7msq control room	143.30	55
Medium ID	Facilities associated with outdoor switchyard with on average 8x220kV or 8x110kV bays and indoor switchgear and control facilities with on average 10x33kV or 10x11kV bays with 103.7sqm control room and 159.6sqm switchgear room	143.30	55
Small OD	Facilities associated with outdoor switchyard with on average 6x110kV and 10x33kV or 10x11kV bays, 86.4msq control room	121.65	55
Small ID	Facilities associated with outdoor switchyard with on average 6x110kV bays and indoor switchgear and control facilities with on average 10x33kV or 10x11kV bays with 86.4sqm control room and 159.6sqm switchgear room	286.87	55
Rural OD	Facilities associated with a rural outdoor switchyard with on average 2x66kV and 6x33kV or 6x11kV bays, 69.1sqm control room	112.95	55
Rural ID	Facilities associated with outdoor switchyard with on average 2x66kV bays and indoor switchgear and control facilities with on average 6x33kV or 6x11kV bays with 69.1sqm control room and 109.2sqm switchgear room	244.86	55

Transformers

Replacement costs for a large number of power transformer options have been provided to cover the range of power transformer sizes and configurations used by Transpower. Generally, costs are provided for power transformers with On-load Tap Changers, except where identified.

Table B. 4: Power Transformer Building Block Costs

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
220	110	11/60	A	3	200	No	2,842.58	55
220	110		A	3	200	Yes	2,535.81	55
220	110	11/60	A	1	200	Yes	1,541.83	55
220	110		A	3	180	Yes	2,372.31	55
220	110	14.5/ 141.5	A	3	141.5	Yes	2,300.44	55
220	110		A	3	120	Yes	2,062.22	55
220	110	11/60	A	3	100	Yes	1,958.86	55
220	110		A	3	100	Yes	1,852.42	55
220	110	11/60	A	1	100	No	1,056.57	55

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
220	110		A	3	90	Yes	1,907.18	55
220	110	33/30	A	3	70	Yes	1,803.81	55
220	110	11/30	A	1	65	No	902.01	55
220	110	11/30	A	3	60	Yes	1,752.13	55
220	110	11/30	A	3	50	No	1,489.46	55
220	110	11/30	A	1	50	No	836.11	55
220	66	11/60	S-S	3	200	Yes	3,047.37	55
220	66	11/60	S-S	1	200	Yes	1,643.80	55
220	66	11/60	S-S	3	100	No	2,151.45	55
220	66	11/60	S-S	1	100	No	1,126.35	55
220	66	33/30	S-S	3	70	Yes	1,930.09	55
220	66	11/30	S-S	1	50	No	917.92	55
220	55		TR	1	18	Yes	820.79	55
220	55		TR	1	15	Yes	778.87	55
220	33		S-D	3	200	Yes	3,278.42	55
220	33		S-D	1	200	Yes	1,315.29	55
220	33		S-D	3	150	Yes	2,715.32	55
220	33		S-D	3	120	Yes	2,366.39	55
220	33		S-D	3	100	Yes	2,273.37	55
220	33		S-D	1	100	Yes	1,000.29	55
220	33		S-D	1	63	No	793.15	55
220	33		S-D	3	60	Yes	1,668.55	55
220	33		S-D	3	50	Yes	1,639.87	55
220	33		S-D	1	50	No	723.70	55
220	33		S-D	1	30	No	616.84	55
220	33		S-D	3	30	Yes	1,319.64	55
220	33		S-D	3	25	Yes	1,261.48	55
220	33		S-D	3	20	No	1,155.49	55
220	33		S-D	3	18	Yes	1,180.06	55
220	33		S-D	3	15	Yes	1,145.17	55
220	33		S-D	3	10	Yes	1,017.85	55
220	33		S-D	3	5	No	925.47	55
220	22		S-D	3	50	Yes	1,632.54	55
220	22		S-D	1	50	Yes	744.47	55
220	16	33/60	S-D	1	240	Yes	1,383.60	55
220	11		S-D	3	100	Yes	2,415.16	55
220	11		S-D	3	70	Yes	1,955.02	55
220	11		S-D	3	60	Yes	1,801.64	55
220	11		S-D	3	12	Yes	1,065.42	55
220	11		S-D	3	10	Yes	1,034.75	55
110	66		D-S	3	60	Yes	1,184.96	55
110	66		D-S	3	55	Yes	1,119.64	55
110	66	11/10	A	1	30	No	498.89	55
110	66	11/10	A	1	20	No	456.02	55
110	66	11/10	A	1	15	No	434.58	55
110	50		D-S	3	30	No	835.05	55
110	50		D-S	1	30	No	451.61	55
110	50		D-S	1	20	No	400.28	55
110	50		D-S	1	15	No	374.61	55

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
110	50		D-S	1	14.1	No	369.99	55
110	50		D-S	3	10	No	663.97	55
110	50		D-S	1	10	No	348.94	55
110	33		D-S	3	120	Yes	1,803.28	55
110	33		D-S	3	100	Yes	1,628.28	55
110	33		D-S	1	100	Yes	797.40	55
110	33		D-S	3	75	Yes	1,403.33	55
110	33		D-S	3	70	Yes	1,358.33	55
110	33		D-S	3	60	Yes	1,268.35	55
110	33		D-S	3	60	Yes	1,268.35	55
110	33		D-S	1	50	No	555.42	55
110	33		D-S	3	50	No	1,084.92	55
110	33		D-S	3	40	Yes	1,088.38	55
110	33		D-S	1	40	No	512.97	55
110	33		D-S	3	38	No	968.60	55
110	33		D-S	3	35	Yes	1,043.38	55
110	33		D-S	1	30	Yes	477.53	55
110	33	11/10	D-S	1	30	No	487.33	55
110	33		D-S	3	30	Yes	1,033.22	55
110	33	11/10	D-S	3	30	No	1,067.96	55
110	33		D-S	3	28	No	871.67	55
110	33		D-S	1	27.5	No	459.92	55
110	33		D-S	3	25	Yes	953.41	55
110	33		D-S	1	20	No	428.08	55
110	33		D-S	3	20	No	859.65	55
110	33		D-S	3	20	Yes	908.41	55
110	33		D-S	3	18	Yes	890.41	55
110	33		D-S	3	15	Yes	833.57	55
110	33		D-S	1	10	No	389.00	55
110	22		D-S	3	50	Yes	1,193.51	55
110	22		D-S	1	50	Yes	604.07	55
110	22		D-S	3	30	Yes	945.94	55
110	22		D-S	1	30	Yes	449.90	55
110	11		D-S	3	60	Yes	1,322.73	55
110	11		D-S	3	50	Yes	1,201.15	55
110	11	33/20	S-D	3	50	Yes	1,253.74	55
110	11		D-S	3	40	Yes	1,078.51	55
110	11		D-S	1	30	No	449.01	55
110	11		D-S	3	30	Yes	955.85	55
110	11		D-S	1	30	Yes	483.78	55
110	11		D-S	3	28	No	884.29	55
110	11		D-S	1	28	No	441.09	55
110	11		D-S	3	27	Yes	919.07	55
110	11		D-S	1	27	Yes	472.31	55
110	11		D-S	3	25	Yes	894.53	55
110	11		D-S	1	25	Yes	461.26	55
110	11		D-S	3	20	Yes	836.52	55
110	11		D-S	1	20	Yes	433.65	55
110	11		D-S	3	15	Yes	771.89	55

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
110	11		D-S	3	10	Yes	710.56	55
110	11		D-S	1	10	Yes	396.65	55
110	11		D-S	1	8	Yes	367.36	55
110	11		D-S	3	7.5	Yes	679.90	55
110	11		D-S	1	7.5	Yes	364.60	55
110	11		D-S	3	5	Yes	649.24	55
110	11		D-S	1	5	Yes	350.79	55
110	11		D-S	1	4.5	No	349.28	55
110	11		D-S	3	4	No	636.19	55
110	11		D-S	3	3	Yes	624.72	55
110	11		D-S	1	2.25	Yes	322.44	55
110	11		D-S	3	1	Yes	597.94	55
66	33		D-S	3	60	Yes	1,113.53	55
66	33		D-S	3	45	Yes	958.40	55
66	33		D-S	3	40	Yes	906.68	55
66	33		D-S	3	20	Yes	699.83	55
66	33		D-S	1	20	Yes	377.70	55
66	33		D-S	3	16	Yes	658.46	55
66	33	11/7.5	A	1	15	No	429.14	55
66	33		D-S	3	15	Yes	648.12	55
66	33		D-S	3	10	Yes	596.41	55
66	33		D-S	3	9	No	537.82	55
66	33		D-S	3	5	Yes	544.69	55
66	33		D-S	1	5	No	260.90	55
66	11		D-S	3	45	Yes	999.11	55
66	11		D-S	3	40	Yes	946.53	55
66	11		D-S	3	30	Yes	841.35	55
66	11		D-S	1	30	Yes	433.23	55
66	11		D-S	3	20	Yes	736.17	55
66	11		D-S	1	20	Yes	366.69	55
66	11		D-S	3	16.5	Yes	699.35	55
66	11		D-S	3	10	Yes	630.99	55
66	11		D-S	1	10	Yes	300.15	55
66	11		D-S	3	5	Yes	578.40	55
66	11		D-S	1	5	Yes	266.88	55
66	11		D-S	1	3.75	No	217.70	55
66	11		D-S	3	3	Yes	557.36	55
66	11		D-S	1	3	Yes	253.57	55
66	11		D-S	3	1	No	361.75	55
66	11		D-S	3	0.5	Yes	531.07	55
50	33		S-S	3	5	No	477.81	55
50	33		S-S	1	5	No	260.90	55
50	11		D-S	1	15	Yes	350.09	55
50	11		D-S	3	7.5	Yes	558.83	55
50	11		D-S	1	7.5	Yes	288.76	55
50	11		D-S	1	5	Yes	268.32	55
50	11		D-S	1	3	No	189.88	55
50	11		D-S	1	2.25	No	219.93	55
50	11		D-S	3	2	Yes	438.30	55

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
33	11		D-S	3	20	Yes	562.58	55
33	11		D-S	3	15	Yes	540.10	55
33	11		D-S	3	13	Yes	531.12	55
33	11		D-S	3	10	No	524.19	55
33	11		D-S	1	10	No	286.45	55
33	11		D-S	3	7.5	Yes	506.39	55
33	11		D-S	3	5	Yes	495.15	55
33	11		D-S	3	2.25	No	357.38	55
33	11		D-S	3	2	No	352.00	55
11	11		A	3	4.5	Yes	494.52	55

Oil Containment

Oil containment is costed based upon the capacity of the facility.

Table B. 5: Oil Containment Building Block Costs

Capacity (m^3)	Description	Maximum Value ($000)	Maximum Life (years)
10	Oil Containment System	68.78	45
15	Oil Containment System	75.24	45
18	Oil Containment System	76.83	45
25	Oil Containment System	80.52	45
30	Oil Containment System	83.16	45
35	Oil Containment System	85.79	45
40	Oil Containment System	88.43	45
45	Oil Containment System	91.07	45
50	Oil Containment System	93.60	45
55	Oil Containment System	96.34	45
60	Oil Containment System	98.98	45
65	Oil Containment System	101.62	45
70	Oil Containment System	104.26	45
75	Oil Containment System	106.90	45
80	Oil Containment System	109.53	45
85	Oil Containment System	112.17	45
90	Oil Containment System	118.46	45
115	Oil Containment System	128.00	45
160	Oil Containment System	149.02	45

Switchgear

Table B. 6: Switchgear Building Block Costs

kV	Description	CB qty	Bus Type	Out/ In	Maximum Value ($000)	Maximum Life (years)4
220	1.5 Line Breaker	1	SB	O	947.20	45
220	1.5 Half Breaker	1	-	O	763.64	45
220	1.5 Transformer Breaker	1	SB	O	631.59	45
220	Transmission Line - No Bus	1	-	O	754.35	45
220	Transmission Line - Single Bus	1	SB	O	835.37	45
220	Transmission Line - Double Bus	1	DB	O	985.22	45
220	Transmission Line - Triple Bus	1	TB	O	1,183.52	45
220	Connection Circuit - No Bus	1	-	O	361.78	45
220	Connection Circuit - Single Bus	1	SB	O	442.80	45
220	Connection Circuit - Double Bus	1	DB	O	592.65	45
220	Connection Circuit - Triple Bus	1	TB	O	790.95	45
220	Generator - No Bus	0	-	O	68.23	45
220	Generator - Single Bus	0	SB	O	149.24	45
220	Generator - Double Bus	0	DB	O	299.09	45
220	Generator - Triple Bus	0	TB	O	497.40	45
220	Bus Section	1	SB	O	418.20	45
220	Bus Coupler - Dual Bus	1	DB	O	980.02	45
220	Bus Coupler - Triple Bus	1	TB	O	1,057.88	45
110	Transmission Line - No Bus	1	-	O	403.29	45

4 Some components of switchgear, in particular infrastructure, currently has a life of 55 years

kV	Description	CB qty	Bus Type	Out/ In	Maximum Value ($000)	Maximum Life (years)4
110	Transmission Line - Single Bus	1	SB	O	476.75	45
110	Transmission Line - Double Bus	1	DB	O	668.04	45
110	Connection Circuit - No Bus	1	-	O	251.62	45
110	Connection Circuit - Single Bus	1	SB	O	325.08	45
110	Connection Circuit - Double Bus	1	DB	O	516.37	45
110	Incomer - No Bus	1	-	O	251.62	45
110	Incomer - Single Bus	1	SB	O	325.08	45
110	Incomer - Double Bus	1	DB	O	516.37	45
110	Generator - No Bus	0	-	O	50.55	45
110	Generator - Single Bus	0	SB	O	124.01	45
110	Generator - Double Bus	0	DB	O	315.31	45
110	Bus Section	1	SB	O	283.42	45
110	Bus Coupler	1	DB	O	836.95	45
110	Bus VT		-	-	46.11	45
66	Transmission Line - No Bus	1	-	O	389.79	45
66	Transmission Line - Single Bus	1	SB	O	454.11	45
66	Transmission Line - Double Bus	1	DB	O	630.83	45
66	Connection Circuit - No Bus	1	-	O	245.48	45
66	Connection Circuit - Single Bus	1	SB	O	309.80	45
66	Connection Circuit - Double Bus	1	DB	O	486.52	45
66	Incomer – No Bus	1	-	O	245.48	45

kV	Description	CB qty	Bus Type	Out/ In	Maximum Value ($000)	Maximum Life (years)4
66	Incomer – Single Bus	1	DB	O	309.80	45
66	Incomer – Dual Bus	1	DB	O	486.52	45
66	Generator – No Bus	0	-	O	48.00	45
66	Generator – Single Bus	0	SB	O	112.32	45
66	Generator – Double Bus	0	DB	O	289.04	45
66	Bus Section	1	SB	O	275.89	45
66	Bus Coupler	1	DB	O	791.92	45
66	Bus VT		-	-	38.96	45
50	Transmission Line – No Bus	1	-	O	386.53	45
50	Transmission Line – Single Bus	1	SB	O	446.23	45
50	Connection Circuit - No Bus	1	-	O	244.78	45
50	Connection Circuit - Single Bus	1	SB	O	304.48	45
50	Incomer – No Bus	1	-	O	244.78	45
50	Incomer – Single Bus	1	SB	O	304.48	45
50	Bus Section	1	SB	O	275.13	45
50	Bus Coupler	1	DB	O	0.00	45
50	Bus VT		-	-	38.96	45
33	OD Feeder – No Bus	1	-	O	221.22	45
33	OD Feeder – Single Bus	1	SB	O	245.40	45
33	OD Feeder – Dual Bus	1	DB	O	283.55	45
33	OD Incomer – No Bus	1	-	O	202.74	45
33	OD Incomer – Single Bus	1	SB	O	223.62	45
33	OD Incomer – Dual Bus	1	DB	O	261.77	45
33	OD Bus Section	1	SB	O	194.96	45
33	OD Bus Coupler	1	DB	O	243.33	45
33	OD Bus VT		-	-	0.00	45
33	Recloser	1	ACR	O	45.21	45

11	OD Feeder - Single Bus	1	SB	O	81.44	45
11	OD Feeder - Dual Bus	1	DB	O	98.66	45
11	OD Incomer - Single Bus	1	SB	O	94.24	45
11	OD Incomer - Dual Bus	1	DB	O	110.51	45
11	OD Bus Section	1	SB	O	90.05	45
11	OD Bus Coupler	1	DB	O	102.54	45
11	Recloser	1	ACR	O	36.43	45
33	Circuit Breaker - Indoor Bus Coupler	1	DB	I	128.80	45
33	Circuit Breaker - Indoor Bus Section	1	SB	I	99.57	45
33	Circuit Breaker - Indoor Feeder	1	SB	I	86.77	45
33	Circuit Breaker - Indoor Feeder - Double Bus	1	DB	I	127.40	45
33	Circuit Breaker - Indoor Incomer	1	SB	I	92.77	45
33	Circuit Breaker - Indoor Incomer - Double Bus	1	DB	I	131.50	45
22	Circuit Breaker - Indoor Bus Coupler	1	DB	I	120.70	45
22	Circuit Breaker - Indoor Bus Section	1	SB	I	87.65	45
22	Circuit Breaker - Indoor Feeder	1	SB	I	83.25	45
22	Circuit Breaker - Indoor Feeder - Double Bus	1	DB	I	119.90	45
22	Circuit Breaker - Indoor Incomer	1	SB	I	84.45	45
22	Circuit Breaker - Indoor Incomer - Double Bus	1	DB	I	124.20	45

11	Circuit Breaker 500MVA - Indoor Bus Coupler	1	DB	I	107.77	45
11	Circuit Breaker 500MVA - Indoor Bus Section	1	SB	I	71.07	45
11	Circuit Breaker 500MVA - Indoor Feeder	1	SB	I	69.47	45
11	Circuit Breaker 500MVA - Indoor Feeder - Double Bus	1	DB	I	107.37	45
11	Circuit Breaker 500MVA - Indoor Incomer	1	SB	I	73.47	45
11	Circuit Breaker 500MVA - Indoor Incomer - Double Bus	1	DB	I	110.67	45
11	Circuit Breaker 750MVA - Indoor Bus Coupler	1	DB	I	232.96	45
11	Circuit Breaker 750MVA - Indoor Bus Section	1	SB	I	98.57	45
11	Circuit Breaker 750MVA - Indoor Feeder	1	SB	I	95.57	45
11	Circuit Breaker 750MVA - Indoor Feeder - Double Bus	1	DB	I	195.16	45
11	Circuit Breaker 750MVA - Indoor Incomer	1	SB	I	145.57	45
11	Circuit Breaker 750MVA - Indoor Incomer - Double Bus	1	DB	I	274.96	45

Reactive Power Plant

Table B. 7: Reactive Power Plant Building Block Costs

Description	Maximum Value ($000)	Maximum Life (years)5
110 kV Two Zone Bus Protection	130.51	15
220 kV Two Zone Bus Protection	130.51	15
66 kV Two Zone Bus Protection	130.51	15
Neutral Earthing Resistor 11kV 12.5 ohms 500A	66.00	45
Neutral Earthing Resistor 22kV 25 ohms 500A	71.00	45
Neutral Earthing Resistor 33kV 37.5 ohms 500A	76.00	45
Neutral Earthing Resistor 17.5kV 2 ohms 300A	66.00	45
Neutral Earthing Resistor 17.5kV 2 ohms 1500A	76.00	45
Neutral Earthing Resistor 17.5kV 2 ohms 3000A	86.00	45
Neutral Earthing Resistor 17.5kV 2 ohms 6400A	96.00	45

Transmission Line

Table B. 8: Transmission Line Building Block Costs

kV	Config	Rating	Conductor	Temp.	Maximum Value ($000)	Maximum Life (years)6
11	scp	220	1/mink	50	36.64	55
33	dcp	315	1/hyena	50	61.98	55
33	dcp	360	1/coyote	50	66.21	55
33	dcp	525	1/wolf	75	74.40	55
33	scp	220	1/mink	50	37.29	55
33	scp	315	1/hyena	50	41.09	55
33	scp	360	1/coyote	50	43.21	55
33	scp	410	1/hyena	75	41.03	55
33	scp	525	1/wolf	75	47.36	55
50	scp	220	1/mink	50	40.00	55
50	scp	315	1/hyena	50	43.80	55
66	dcst	315	1/hyena	50	112.14	55
66	dcst	410	1/hyena	75	114.37	55
66	dcst	525	1/wolf	75	137.48	55
66	dcst	640	1/goat	50	170.65	55
66	dcst	1960	2/zebra	75	318.88	55

5 Life of Neutral Earthing Resistors to be confirmed
6 Transmission lines are assigned lives according to environmental factors (see B.46).

kV	Config	Rating	Conductor	Temp.	Maximum Value ($000)	Maximum Life (years)6
66	dcp	290	1/mink	75	65.92	55
66	dcp	525	1/wolf	75	90.07	55
66	dcp	640	1/goat	50	115.38	55
66	scst	315	1/hyena	50	91.61	55
66	scp	220	1/mink	50	40.84	55
66	scp	315	1/hyena	50	44.64	55
66	scp	360	1/coyote	50	46.77	55
66	scp	410	1/hyena	75	44.28	55
110	dcst	315	1/hyena	50	123.14	55
110	dcst	360	1/coyote	50	128.81	55
110	dcst	410	1/hyena	75	125.92	55
110	dcst	525	1/wolf	75	141.18	55
110	dcst	640	1/goat	50	176.57	55
110	dcst	750	1/zebra	50	194.99	55
110	dcst	840	1/goat	75	180.55	55
110	dcst	980	1/zebra	75	195.41	55
110	dcst	1050	2/wolf	75	223.74	55
110	dcst	1280	2/goat	50	295.26	55
110	dcst	1500	2/zebra	50	321.20	55
110	dcst	1640	1/chukar	75	273.37	55
110	dcst	1680	2/goat	75	296.05	55
110	dcst	1960	2/zebra	75	324.84	55
110	dcp	400	1/wolf	50	97.00	55
110	dcp	525	1/wolf	75	100.14	55
110	scst	315	1/hyena	50	91.57	55
110	scst	360	1/coyote	50	96.61	55
110	scst	410	1/hyena	75	92.98	55
110	scst	525	1/wolf	75	104.48	55
110	scst	640	1/goat	50	128.46	55
110	scp	315	1/hyena	50	51.41	55
110	scp	360	1/coyote	50	53.48	55
110	scp	410	1/hyena	75	53.91	55
110	scp	525	1/wolf	75	57.02	55
110	scp	640	1/goat	50	66.05	55
220	dcst	750	1/zebra	50	210.54	55
220	dcst	980	1/zebra	75	212.97	55
220	dcst	1280	2/goat	50	319.92	55
220	dcst	1500	2/zebra	50	353.41	55
220	dcst	1640	1/chukar	75	307.03	55
220	dcst	1680	2/goat	75	324.31	55
220	dcst	1960	2/zebra	75	362.80	55
220	dcst	3280	2/chukar	75	538.91	55
220	scst	640	1/goat	50	132.34	55
220	scst	750	1/zebra	50	146.96	55
220	scst	980	1/zebra	75	149.87	55
220	scst	1280	2/goat	50	210.85	55

Table B. 9: Seismic adjustment factors (for substations)

Equipment Type	Zone A *(high risk)*	Zone B *(medium risk)*	Zone C *(low risk)*
Establishment	1.14	1.06	1.00
Buildings	1.02	1.01	1.00
Oil Containment	1.14	1.06	1.00
Transformers	1.04	1.02	1.00
Switchgear	1.02	1.01	1.00
Other Plant	1.02	1.01	1.00

Table B.10: Interest during construction factors

Asset Type	Factor (Annualised Rate)
Substation assets	4.0%
Transmission line assets	4.8%

APPENDIX C: OPTIMISATION FOR ELECTRICITY LINE BUSINESSES

Optimisation of the System Configuration

(a) Connection/Supply Points (including embedded generation connections)

Issue: Whether all existing points of supply are required, given the ELB's disclosed quality of supply criteria.

Approach: Location and supply voltage should be considered as fixed. All points of supply must be tested to determine whether a lower value network would result if the point of supply were eliminated and the load supplied from adjacent points of supply.

(b) Transmission/Subtransmission Lines

Issue: Whether the number of transmission/subtransmission lines exceeds the number required given the ELB's disclosed quality of supply criteria and allowed future load growth.

Approach: Location and voltage of both the point of supply and the zone substation should be considered to be fixed. Assess the number of transmission/subtransmission lines in relation to the ELB's disclosed quality of supply criteria and allowed future load growth. Optimise out those that are not required.

(c) Substations/Zone Substations

Issue: Whether the number and capacity of substations/zone substations exceeds that which is required to meet the ELB's disclosed quality of supply criteria and allowed future load growth.

Approach: The location of the substation/zone substation should be considered to be fixed. All substations/zone substations must be tested to determine whether a lower value network would result if the substation/zone substation were eliminated and the load supplied from an adjacent substation/zone substation.

Issue: Customer requirements vary

Approach: Identify customers with special requirements covered by specific non-standard contracts and optimise the substation/zone substation configuration to satisfy these customers without materially changing the security or customer service standard of other customers.

(d) Distribution Lines

Issue:	Whether the number of distribution lines or feeders exceeds that which is required, given the ELB's quality of supply criteria and allowed future load growth.
Approach:	Assess the number required in relation to the ELB's disclosed quality of supply criteria and allowed future load growth. Optimise out feeder connections and lines that are not required. Additional notional distribution lines will not result from this optimisation.
Issue:	Whether the number of high voltage switches on the distribution network exceeds the number required given disclosed quality of supply criteria
Approach:	Assess the number of switches on the network in relation to the ELB's disclosed quality of supply criteria. Optimise out any switches that are not required
Issue:	Use of very low capacity or less than three phase distribution lines.
Approach:	Where the existing distribution line or a part of it is of less than 3 phase construction, the line must be valued accordingly. Where the distribution line or a part of it is of 3 phase construction it will be valued at the lowest replacement cost of a line that meets the disclosed quality of supply criteria including allowance for future load growth.

Transpower

Security Guidelines for Transmission Planning				
Load (MW)	**Basic Security**	**Transmission Circuits**	**Busbars**	**Transformers**
Less than 10	n	One circuit	One bus or bus section	1 x 3-phase units.
(10 to 40, if more than 40km remote and local generation can limit load shed to 25%)	n	One circuit	One bus or bus section	4 x 1-phase or 1 x 3-phase unit, if backed up from alternative supply point.
From 10 to 300	n-1	Two circuits	Two busbars or bus sections	7 x 1-phase units or 2 x 3-phase units. Firms supply of peak demand using any short term overload capability.
More than 300	n-2	Three circuits on at least two routes	One redundant bus or bus section, such that supply is not lost after a single contingency while one bus is out of service for maintenance	7 x 1-phase units or 2 x 3 phase units. Firms supply of peak demand using any short term overload capacity
More than 600	Loss of station	Supply into region should be diversified across more than one major terminal substation.		

Optimisation of Elements in the System

(a) Transmission/Subtransmission Lines and Cables

Issue: Conductor and cable size.

Approach: Determine the required capacity, being the maximum demand and load cycle the line or cable will be exposed to during the planning period, given the disclosed quality of supply criteria and allowed future load growth.

Optimise down the size of the conductor or cable to the smallest standard size shown in Appendix B that meets the required capacity utilising the short term ratings of the conductors or cables and the disclosed quality of supply as appropriate.

Issue: Overhead / underground transmission.

Approach: If a distribution line consists of underground cables these must be valued as overhead lines of the required capacity unless there is specific evidence that the local authority would not, in normal circumstances, grant consent for overhead reticulation, or that a non-standard contract or a legal obligation requiring the installation of underground lines exists.

Issue: Underground Distribution Trenching

Approach: If more than one underground cable is laid in a trench only the cost of the additional cable(s) may be valued for those additional cables i.e. the trenching may only be valued for one cable.

(b) Substations/Zone Substations

Issue: Transmission/subtransmission substation design.

Approach: Optimise the overall design of the substation (including the need for more than a single bus bar) to the minimum required to meet the disclosed quality of supply criteria and allowed future load growth.

Issue: Under-utilised equipment is often installed at substations.

Approach: Optimise out substation equipment not required to meet the disclosed quality of supply criteria and allowed future load growth.

Optimise the size of the equipment used to nearest standard rating to not exceed the allowed future load growth.

Issue: Land and Buildings.

Approach: Optimise indoor substations to outdoor where land is available and this will result in a lower replacement value network unless there are clear technical reasons or local authority requirements that prevent this.

Optimise out any unutilised, or under utilised land so that the value of the land allowed reflects only the area of land required to meet the ELB's disclosed quality of supply criteria and allowed future load growth.

Reduce the replacement cost to that of a simple standard modern structure using pre-fabricated or other low cost designs. The size of the optimised design should not exceed that required to meet the essential functionality of the building.

Issue: Ancillary equipment.

Approach: Optimise out if not required to meet the ELB's disclosed quality of supply criteria.

Issue: Fire protection and oil retention facilities.

Approach: Include unless not required for Modern Equivalent Assets.

(c) Substation/Zone Substation Transformers

Issue: Numbers of Transformers.

Approach: Reduce the overall replacement cost of the transformers by optimising the number and arrangement of transformers that will meet and not exceed the ELB's disclosed quality of supply criteria.

Issue: Transformer rating.

Approach: Determine nominal, forced cooled, cyclic and short-term ratings. When optimising the equipment full use should be made of the forced cooled capacities and short-term ratings of the equipment in order to determine the transformer capacity to meet the ELB's disclosed quality of supply criteria. The transformer size should be optimised down so that it will require 100% of its capacity to meet the allowed future load.

Issue: Cable or circuit breaker or other equipment constraints.

Approach: Derate transformers to the lowest rating of any piece of equipment associated with the transformer.

(d) High Voltage Distribution

Issue: Conductor and cable size.

Approach: Examine thermal ratings, faults and current levels to determine minimum conductor size for each feeder, given the disclosed quality of supply criteria and allowed future load during the allowed planning period. Optimise down where necessary.

Issue: Overhead/Underground Distribution.

Approach: If a distribution line consists of underground cables these must be valued as overhead lines of the required capacity unless there is specific evidence that the local authority would not, in normal circumstances, grant consent for overhead reticulation, or that a non-standard contract or a legal obligation requiring the installation of underground lines exists.

Issue: Underground Distribution Trenching

Approach: If more than one underground cable is laid in a trench only the cost of the additional cable(s) may be valued for those additional cables i.e. the trenching may only be valued for one cable.

Issue: Achievement of satisfactory customer voltage.

Approach: The optimisation of each feeder must include consideration as to whether the existing customer service standard (in particular the voltage) is being achieved in the most cost-effective manner. A more cost-effective network may result from reducing the conductor size and utilising other means such as voltage regulators, and reactive compensators to maintain the disclosed quality of supply criteria throughout the length of the feeder.

(e) Voltage Control Devices

Issues: Degree of control.
Manual and on load tap changes.
Line regulators and line drop compensation.
Reactive compensation.

Approach: Test requirements for all items in the optimised network and optimise out where there is no clear justification for the equipment.

(f) Distribution Transformers (pole, kiosk, ground types)

Issue: Transformer rating.

Approach: Optimise out excess distribution transformer capacity so that the capacity utilisation (ratio of current peak load to total distribution transformer capacity) for the network is not less than 30% unless a lower utilisation is provided for in a specific customer non-standard contract. Transformer capacity optimised out shall be valued at the average DRC per kVA of the ELB's transformer equipment.

(g) Low Voltage Distribution

Issue: Overhead / underground reticulation.

Approach: If the low voltage distribution consists of underground cables these must be valued as overhead lines of the required capacity unless there is specific evidence that the local authority would not, in normal circumstances, grant consent for overhead reticulation, or that a non-standard contract or a legal obligation requiring the installation of underground lines exists.

Issue: Underground Distribution Trenching

Approach: If more than one underground cable is laid in a trench only the cost of the additional cable(s) may be valued for those additional cables i.e. the trenching may only be valued for one cable.

Issue: Services and load control equipment.

Approach: Standardise to minimum requirements to meet disclosed quality of supply criteria.

Issue: Whether the standard or quantity of low voltage distribution lines and equipment exceeds that which is required given the ELB's disclosed quality of supply criteria and allowed future load growth.

Approach: Identify any parts of the network where the standard of low voltage distribution is higher than required by the disclosed quality of supply criteria and optimise out excess assets.

(h) System Control

Issue:	Degree of sophistication of SCADA equipment.
Approach:	Determine whether equipment is appropriate on the basis of disclosed quality of supply criteria.
Issue:	Need for load control system and degree of sophistication.
Approach:	Determine whether equipment is appropriate on the basis of disclosed quality of supply criteria.

APPENDIX D: THE WEIGHTED AVERAGE COST OF CAPITAL (WACC)

D.1 The weighted average cost of capital (WACC) is the minimum acceptable return on investment required by lenders and shareholders. It is the weighted average cost of debt and equity funded capital and is the appropriate rate to discount future Free Cash Flows (FCF) to their Present Value (PV).

D.2 The WACC is used for EV valuation purposes. First is used in assessing whether network segment assets can sustain an Optimised Depreciated Replacement Cost (ODRC) valuation, or whether they should be valued at EV. Secondly if such assets are unable to sustain an ODRC valuation, the WACC is used to discount the future expected cash flows of those assets to calculate their PV and EV.

D.3 The WACC may be defined in alternative ways. Below a commonly used definition is presented. The handbook does not mandate the definition to be used, but whatever WACC formulation is used, it should be consistent with the formulation of the cash flows to be discounted. The WACC in this handbook has been specified from a New Zealand investor perspective. It is presented as post-investor tax to reflect New Zealand's dividend imputation regime, and it is set in nominal (not real) terms consistent with FCF.

The WACC Formula

D.4 The WACC may be determined as:

$$WACC = R_e \frac{E}{V} + R_d (1 - t_c) \frac{D}{V}$$

where: R_e = *cost of equity capital*

R_d = *cost of debt*

E = *market value of equity*

D = *market value of debt*

$V = D + E$ = *total value of business*

t_c = *corporate tax rate on debt.*

Cost of Equity Capital *(R_e)*

D.5 The cost of equity capital *(R_e)* is the return required by investors to compensate them for the variability of bottom line profits. It is equivalent to a cost of capital which includes both business risk (arising from the variability of operating cash flows, and financial risk (arising from the variability of residual cash flows after paying interest payments out of uncertain profits).

D.6 R_e may be determined using the Capital Asset Pricing Model (CAPM) as:

$$R_e = R_f (1-t_c) + ß_e [R_m - R_f (1-t_c)]$$

where: R_f = *risk free rate*

R_m = *return on the market portfolio of shares post-investor tax*

R_m-$R_f (1-t_c)$ = *equity market risk premium post-investor tax*

$ß_e$ = *equity beta (levered).*

D.7 The CAPM can be configured on either a pre or post-investor tax basis. The latter is theoretically superior and the handbook has adopted its use. This does not preclude the use of WACC on a pre-investor tax basis but the inputs to the WACC will differ from those discussed below.

The Risk Free Rate *(R_f)*

D.8 The most suitable risk free rate is a government stock rate, say for 5 year stock. This rate is widely available as active trading in 5 year government stock means it is likely to be an equilibrium rate, and it is the generally accepted indicator of the risk free rate.

Equity Market Risk Premium *R_m-R_f (1-t_c)*

D.9 The post-investor tax market risk premium can be calculated from New Zealand share market data. An estimate should be used for this factor which is both theoretically and empirically defensible. The basis of measurement should be consistent with that used for the determination of the equity beta coefficient.

Equity Beta *(b_e)*

D.10 The equity beta coefficient will depend on the relative business and financial risk of each ELB. Equity betas can be expressed in terms of a asset betas, which are a measure of relative business risk alone (the financial risk of leverage is excluded from asset betas). The relationship of equity betas to asset betas is:

$$ß_e = ß_a (1 + D/E)$$

where: $ß_e$ = *equity beta (levered)*

$ß_a$ = *asset beta (unlevered).*

D.11 Asset betas can be estimated from of firms listed on the New Zealand Stock Exchange with comparable levels of business risk as well as firms listed on overseas markets. Shares in electricity utilities are traded on a number of overseas markets. However, caution and judgement is required in applying data derived from other markets as this may be derived from capital markets which exhibit different characteristics to New Zealand capital markets.

The Cost of Debt *(R_d)*

D.12 The borrowing rate should be estimated as the risk free rate plus a premium that will reflect the riskiness of the debt of the particular line ELB:

$R_d = R_f + \textit{Debt Premium.}$

The Debt and Equity Ratios *(D/V and E/V)*

D.13 The debt and equity ratios should be set consistent with ratios considered to be prudent by equity markets for comparable businesses. As well as referring to the New Zealand market which has limited examples of such businesses, examination of overseas markets may provide useful input.

D.14 An important factor influencing a particular firm's debt ratio is the level of business risk facing the firm. A low risk firm with stable cash flows can prudently support a high debt ratio. A firm with higher risk characteristics will normally only be able to support lower debt levels as troughs in its more volatile cash flow could create liquidity problems if debt (and therefore debt servicing cost) is relatively high.