DECEMBER 2008

Asset Management Plan

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Limited The National Grid

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1 EXECUTIVE SUMMARY

Transpower's Asset Management Plan (AMP) represents the intended asset management strategies and programmes of work for the National Grid infrastructure and related assets. It describes the significant 'business as usual' investment undertaken annually to maintain grid assets and perform minor equipment upgrades, and includes a summary of all planned operating and capital expenditure, including major grid reliability and grid investment expenditures.

Transpower's early adoption and development of asset management practices over the last two decades is a good foundation for the existing capabilities of its people, systems, processes and standards. However an important element of asset management practice is the need to continually review and improve these capabilities.

The AMP presents Transpower's intended programmes of asset management works for the National Grid, based on Transpower's understanding of customer and stakeholder requirements, our knowledge of the existing and projected grid assets, the measured and expected condition of the assets, and the required and expected asset performance requirements.

The intended audience for the AMP includes the Electricity Commission, the Commerce Commission, Transpower customers and end-use consumers of power, and other stakeholders with interests in Transpower's asset management strategies and plans.

The AMP is part of a suite of planning documents that make up Transpower's planning framework along with the Annual Planning Report, the Grid Upgrade Plans, the Asset Works Plan, and the Business Plan.

Existing grid assets

The major National Grid assets include over 11,000 route km of transmission lines; about 25,000 towers and 16,000 poles; and 175 substations with over 1,000 power transformers and about 2,300 circuit breakers. The high-voltage direct current (HVDC) link between the North and South Islands includes 40 km of submarine cables under Cook Strait and two converter stations at Benmore and Haywards.

Additional assets include the information technology and telecommunications equipment and infrastructure related to the grid, metering assets, and property and easements owned for the purpose of building, maintaining and operating the grid assets.

Asset Maintenance Programmes

The main outcomes of this AMP are the maintenance programmes covering each category of asset held by Transpower. The goal of the programmes is to achieve sustainable assets and to deliver the grid now and in the future. Transpower aims to maintain least-cost service quality and capability by managing existing and new grid assets reliably, safely, efficiently and economically. To achieve this goal, Transpower considers the asset status, condition assessment information and performance requirements for each asset and establishes the planned actions required to meet reliability and performance targets.

Levels of service

The intentions of Transpower's AMP are to provide the following outcomes:

- the safety of the public and of staff and contractors
- a quality of supply that at least meets regulatory standards (as measured by the Commerce Commission's current measures)

- a sustainable and improving overall level of performance of the National Grid.

Land access

The majority of Transpower's transmission lines have been established under legislation that ensures that the lines are lawfully established. This lawful establishment allows Transpower to inspect, maintain, repair and upgrade the works subject to there being no injurious affect caused to the land.

With the establishment of easements for new lines, access to existing lines has become increasingly difficult and time-consuming to negotiate. Landowner expectations of payment of compensation for existing works are causing issues. Transpower has a strategy for establishing "access agreements" on an individual basis as required. It is intended that working relationships with landowners will improve as the agreements are put in place.

2 INTRODUCTION

Transpower's Asset Management Plan (AMP) represents the programmes of work for the National Grid infrastructure and related assets.

This comprehensive plan describes the significant investment undertaken annually to maintain grid capability. It also includes a summary of all planned operating and capital expenditure, including major grid reliability and grid investment expenditures.

The AMP document includes:

- status of existing assets and programmes for their maintenance
- routine maintenance and repair plans for assets
- financial summary of capital and operating expenditure.

While this document is maintained as a stand-alone document, it is also incorporated into the Grid Upgrade Plan (GUP) framework.

Transpower has a medium term plan to enhance the provision of information in the Asset Management Plan. In particular, future publications will provide more details about performance and risk issues associated with the existing assets. More explicit links will be made between the performance and risk issues, the asset management strategies, and the planned expenditure. Future publication dates will be revised to provide a closer link to the latest 10 year expenditure plans. The next publication will include many of the planned enhancements. The next publication date that will include additional information is tentatively scheduled for June 2009.

This version is an interim update of the AMP published in September 2007. Only limited changes have been made to the 2008 version, focussing on updates in the areas of HVDC Pole 1, power transformers, and synchronous condensers. A full update will be provided in the June 2009 publication.

2.1 Asset Management Review

In September 2008, Transpower published the findings of an independent review of its asset management practices. The review was carried out by DuPont, in association with BW Consulting.

See: http://www.gridnewzealand.co.nz/asset-management-review

The main recommendations from the review can be briefly summarised as follows:

- o Develop an assertive replacement plan for aging assets.
- o Establish strategic spares for the asset categories of transformers and circuit breakers.
- o Investigate enhancements to the asset management information systems
- o Reposition Transpower's approach to the control of intellectual property concerning detailed maintenance requirements

This edition of the AMP includes some responses to the asset management review. However, the full implementation of the recommendations will take a considerable period of time. Subsequent editions of the AMP will include further action plans resulting from the review.

2.2 Purpose of Asset Management Plan

The purpose of Transpower's AMP is to present Transpower's programmes of asset works for the infrastructure that makes up the National Grid. These programmes are presented based on Transpower's understanding of customer and stakeholder requirements, Transpower's knowledge of the existing and projected grid assets, the measured and expected condition of the assets, and the required and expected asset performance requirements.

The AMP aims to translate Transpower's goals and objectives, the requirements of stakeholders, and the technical and practical requirements of the assets into programmes of work and plans of action to meet these requirements. The AMP outlines how Transpower manages existing and new grid assets reliably, safely, efficiently and economically to maintain service quality and quantity obligations in a least-cost way.

Transpower produces an AMP as a primary input into each GUP submitted to the Electricity Commission. The GUP also covers major grid reliability and grid economic investments proposed in accordance with Part F of the Electricity Governance Rules & Regulations. In this context, this Asset Management Plan in intended to fulfil the requirements of Part F, Rule 12.3.1 as a "comprehensive plan for asset management and operation of the grid".

The intended audience for the AMP extends beyond the Electricity Commission and Part F requirements for GUPs. Transpower's other regulator, the Commerce Commission, uses the AMP as a reference for proposed expenditure. Transpower also intends that customers, end-use consumers of power and other stakeholders with interests in Transpower's proposed activities will find the AMP a useful, informative document. It is intended to communicate these plans to all stakeholders, consistent with their interests in Transpower.

The intentions of Transpower's AMP are to provide the following outcomes:

- the safety of the public and of staff and contractors
- a quality of supply that at least meets regulatory standards (as measured by the Commerce Commission's current measures)
- a sustainable and improving overall level of performance of the National Grid.

3 ASSET MANAGEMENT PROGRAMMES

This section describes Transpower's existing assets by category with summary information on the different types and age profiles. For each asset category, details are then provided on the asset management approach, status and planned actions for each category of assets

The goal of the life cycle approach is to achieve sustainable asset management and to deliver the grid now and in the future. To achieve this, Transpower considers the asset status, condition assessment information and performance requirements for each asset and establishes the planned actions required to meet reliability and performance targets.

Transpower's existing assets encompass a wide range of types and ages, recognising that the economic life of some transmission assets is up to 70 years. Given that the last period of significant grid investment occurred in the 1950s and 60s, an increasing emphasis is being placed on assessing asset condition, performance and risk to determine the optimum time for planned repairs, refurbishments or replacements. It must be noted that not all future investment requirements have been identified in the AMP for future years, particularly in the longer term. However, the forecasts contained in the AMP provide specific targets over the next five years, where age and condition information are available to justify the expenditure.

The longer-term forecasts will be reviewed and updated as better information becomes available and the results of technical analysis and cost justification studies are completed to confirm future plans.

AC substations are covered in Section 3.2, protection and control equipment is addressed in Section 3.3, metering in Section 3.4, transmission lines in Section 3.5, HVDC in Section 3.6, SCADA and telecommunications equipment in Section 3.7, and property, easements and consents in Section 3.8. Routine maintenance and repairs are covered in Section 4.

3.1 Existing Grid Assets

Transpower's existing grid assets include over 11,000 route km of transmission lines; about 25,000 towers and 16,000 poles; and 175 substations with over 1,000 power transformers and approximately 2,300 circuit breakers.

The high-voltage direct current (HVDC) link between the North and South Islands includes 40 km of submarine cables under Cook Strait and two converter stations (at Benmore and Haywards) converting power from alternating current (AC) to direct current (DC). The HVDC link has two poles operating at 270 kV (Pole 1) and 350 kV (Pole 2) and an overland transmission line linking Benmore to Fighting Bay at the southern end of the submarine cables. The HVDC Pole 1 converter stations are only available at times of critical system need, and are subject to restricted operating conditions.

Information technology and telecommunications assets form a critical part of the National Grid asset base. Substation data acquisition is supported by 347 remote terminal units (RTUs) and 26 substation control systems associated with the national supervisory control and data acquisition (SCADA) system.

Transpower's telecommunications network includes a mix of different technologies with a wide range of ages and capabilities. Telecommunication assets include antennas and networking, local electricity supply, fibre optics, DC and other communications equipment, communication systems, external communications lines, multiplexing and interfacing equipment, powerline cable carriers, radio towers, radios and telephone equipment.

Transpower is also responsible for the supply and management of 392 grid exit point (GXP) meters installed at 148 sites on the grid.

3.2 AC substations

The AC substations asset class comprises all plant and equipment inside stations, including transformers, switchgear, structures and buswork, reactive support equipment, together with substation buildings and grounds.

Transpower's system has 173 substations (including two HVDC cable stations), most built between 1920 and 1970.

3.2.1 Gas-insulated substations (GIS)

STATUS

There are six gas-insulated substations (five 220 kV and one 110 kV), all commissioned since 1979, with an average age of 21 years.

The six Mitsubishi gas-insulated substations are generally in good condition apart from one underground 220 kV GIS station at Rangipo. This station, commissioned in 1983, has ongoing SF_6 gas leaks from flange seals. Managed replacement of 80% of the seals has minimised SF_6 leaks from this equipment but some continuing remedial work is expected to be required.

ACTION

Non-invasive condition monitoring inspections and tests (including gas quality tests) are undertaken every eight years. Invasive pilot inspections of circuit breakers representative of each type and service duty are scheduled after 12 to 16 years of service. Circuit-breaker operating rods of one type of 220 kV GIS are also inspected periodically to check for any sign of transient discharge damage.

3.2.2 Outdoor circuit breakers

STATUS

Transpower's system has 1,663 outdoor circuit breakers operating at voltages from 11 kV to 220 kV (see Table 3-1).

Table 3-1: Number of outdoor circuit breakers by type and voltage

	HVDC	220	110	66	55	50	33	22	11	Total
Air blast		21	4	0	0	0	0	0	0	25
Bulk oil		5	77	44	0	0	369	6	17	518
Minimum oil	6	1	38	15	0	0	39	0	0	99
SF6	6	398	400	76	8	13	91	0	8	1000
Vacuum		0	0	0	0	0	0	0	21	21
Total	12	425	519	135	8	13	499	6	46	1663

Older technology oil circuit breakers now comprise only 37 per cent of the population and SF_6 circuit breakers make up 60 per cent, as a result of the continuing conditioned-based replacement of aged equipment, as shown in Figures 3-1 and 3-2.

Figure 3-1: Outdoor switchgear age profile

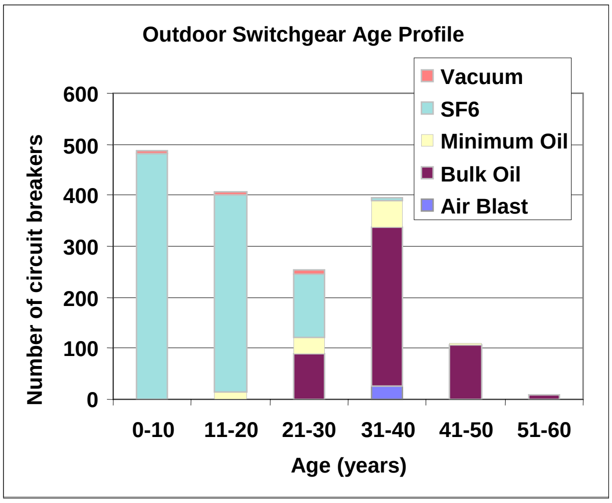
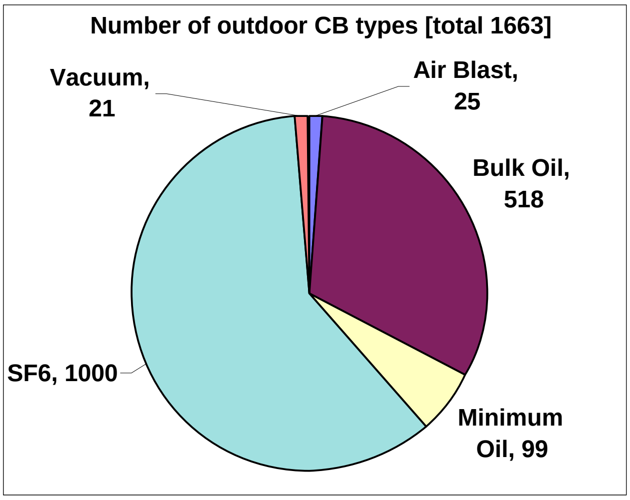


Figure 3-2: Outdoor circuit breaker types



The economic service life for circuit breakers on Transpower's system varies according to the particular technology, which normally relates directly to age, but also to service duty. Most circuit breakers usually operate infrequently except for some, such as those used for switching shunt capacitor banks and HVDC harmonic filter banks, which have a correspondingly shortened life expectancy.

Based on historical data, the expected life for air blast, vacuum, SF_6 and minimum oil circuit breakers is 35 years, and is 45 years for bulk oil circuit breakers. Since the replacement programme started in 1988, the average age has reduced from 25 years to around 21 years. The number of circuit breakers over 40 years old is down from 13.5 per cent in 1993, to 9.7 per cent in 2001 and 7 per cent in 2007.

A large proportion of aged, maintenance-intensive and unreliable oil circuit breakers have been replaced. This includes both bulk and minimum oil types, which were the predominant outdoor circuit breakers in the 66 to 110 kV range.

SF_6 circuit breakers

SF_6 circuit breakers are now the main type on the system at voltages 66 kV and above. These have increased system reliability and greatly reduced maintenance costs but their life expectancy, at 35 years, is 10 to 15 years less than the older technology equipment they replace.

Most circuit breakers bought since 1975 are SF_6 (gas) type and are generally in good serviceable condition requiring little maintenance. Some designs have suffered from premature corrosion, leading to SF_6 gas leaks. Two of the 1970s models are progressively being replaced. SF_6 circuit breakers bought after 1995 have improved corrosion protection systems that should deliver a life of up to 35 years.

Bulk oil circuit breakers

Bulk oil circuit breakers currently make up 31 per cent of the total population. Of these, 71 per cent are rated at 33 kV and were supplied between 1956 and 1983. Around 80 per cent of the outdoor 33 kV bulk oil circuit breakers are now more than 30 years old.

Outdoor bulk oil 33 kV circuit breakers have poor operational performance and high maintenance costs and defect rates compared with the modern equivalent indoor 33 kV circuit breaker. Corrosion of mechanism cabinets and circuit breaker housings is increasingly common, particularly in polluted environments. Most of the 33 kV bulk oil circuit breakers are installed beneath pole or gantry type outdoor 33 kV structures. Maintenance difficulties associated with the small clearances in these structures are another driver for a review of the future replacement strategy.

Minimum oil circuit breakers

Minimum oil circuit breakers, which make up 6 per cent of the population, continue to show age-related insulation deterioration, particularly at 33 kV, as well as mechanism wear and a reduced level of reliability.

Air blast circuit breakers

Air blast circuit breakers in the range 110 to 220 kV make up 1.5 per cent of the overall total. Following the 2007-08 replacements, the only remaining 220 kV model will be at Twizel with replacement planned in 2009-11.

This complex technology needs a high level of maintenance expertise. Overhaul and repair costs are high due to the cost of specialised consumable spares, and the frequency and large amount of work required for maintenance. Outages required for maintenance of these circuit breakers also place constraints on system availability. Centralised compressed air systems with high-pressure air compressors are typically required for air blast circuit breakers. These air compressors have a shorter life than the circuit breakers themselves, and have high maintenance costs.

ACTION

Maintenance

Condition-monitoring tests and inspections are carried out at intervals from two to eight years according to circuit breaker type. The frequency and methods of testing are reviewed regularly to improve the management of these assets.

Insulation condition and mechanical performance are monitored and the integrity of stored energy systems (hydraulic and pneumatic) compared with specified tolerances. Trends, based on past records, are established and used to plan modifications, refurbishments or replacement.

Refurbishment and repairs

Major refurbishment of circuit breakers or repairs involving replacement of major components are becoming uneconomic, and generally carried out only when the cost is less than 35 per cent of the cost of a new circuit breaker and where a further 10 years of reliable life is possible.

Planned repairs include minor corrosion repairs to some bulk oil 33 kV circuit breakers. The economics of full refurbishment of 33 kV bulk oil circuit breakers is now marginal for their limited remaining expected life.

Flange corrosion in some models of SF_6 circuit breakers has led to gas leaks. Repairs are often not economic and are generally only short-term, giving five to 10 years of extended life. A number of SF_6 circuit breakers switching capacitor banks and harmonic filter banks have needed replacement operating mechanisms and the refurbishment of some interrupter poles, because of wear resulting from very frequent operation. The design of some of these circuit breakers is not suited to very frequent switching duty and replacement may be required during the next 10 years.

Replacement

Circuit breakers are nominally scheduled for replacement when they have reached the end of their economic life. However, actual replacement decisions are based on condition assessment, performance trend analysis, reliability and safety considerations, and the costs of refurbishment and maintenance.

There is an historic relationship between circuit breaker replacement programmes and improvements in system reliability, with a marked decrease in system minutes lost because of reduced circuit breaker failures over the past two decades.

The current 10-year replacement programme targets aged oil circuit breakers in the 33 to 110 kV voltage range and air blast circuit breakers. Avoiding the escalating costs of maintenance and replacement of centralised compressed air systems is also driving replacement of air blast circuit breakers.

Table 3-2: Outdoor circuit breaker replacement programme

All Regions	**08-09**	**09-10**	**10-11**	**11-12**	**12-13**	**13-14**	**14-15**	**15-16**	**16-17**
220 kV	5	1	1	7	8	17	2	14	
110 kV			16	3	3	10	7	7	16
66 kV		2		2	3	4	13	2	15
33 kV		1	37	24	29	24	19	39	22
22 kV								6	
11 kV			10	1		1			1
Total Qty	**5**	**4**	**64**	**37**	**43**	**56**	**41**	**68**	**54**

During 2008-09, the condition assessment and replacement drivers for 33 kV oil circuit breakers will be reviewed. The review will include a re-evaluation of the benefits and criteria for outdoor-to-indoor conversions of aged 33 kV switchyards. This work will lead to significant changes in the current planned replacement programme that will bring forward some replacement projects and reduce the peaks in forecast circuit breaker replacements currently shown between 2010 and 2017.

Five-year forecast

Within five years, all 110 & 220 kV air blast circuit breakers are expected to have been replaced, enabling the removal of the associated high maintenance, high pressure air compressor systems. The large stock of spares for both the circuit breakers and compressors can be eliminated, reducing inventory value and storage. The minimum oil circuit breaker replacements will remove two of the three remaining 110 kV models.

3.2.3 Indoor metal-clad switchgear

STATUS

There are 69 indoor metal-clad switchboards at Transpower stations, operating at 11, 16, 22 and 33 kV with an average age of 22 years. Before about 1975, oil was the main interrupting medium for indoor circuit breakers. Since then, the interrupters in switchboards are mainly either vacuum or SF_6 gas types.

11 kV switchboards currently account for 68 per cent of the indoor switchboard population. Of the 11kV population, eight were commissioned before 1960, including one before 1950.

The remaining indoor switchgear population consists of 20 switchboards operating at 33 kV, and three at 22 kV, all supplied since 1981, apart from one 33 kV board supplied in 1974. There is also a 16 kV switchboard at Benmore, installed in 1963.

Table 3-3: Indoor circuit breakers by type and voltage

Type	33	22	16	11	Total
Air Blast	0	0	6	23	29
Bulk Oil	12	0	0	224	236
Minimum Oil	0	0	0	17	17
SF_6	96	18	0	11	125
Vacuum	29	4	0	164	197
Total	137	22	6	439	604

Figure 3-3: Indoor switchgear age

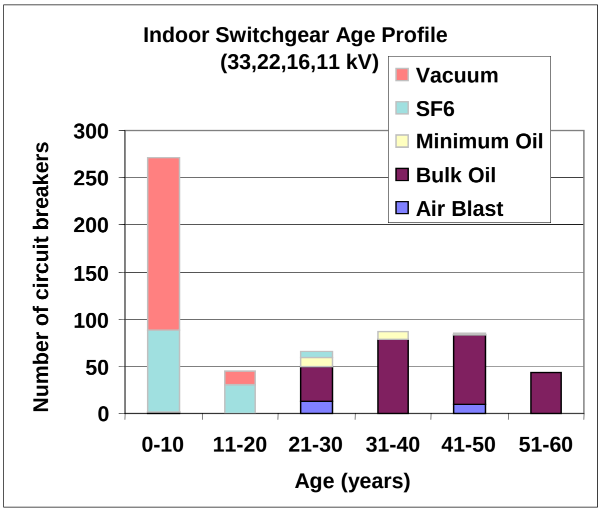
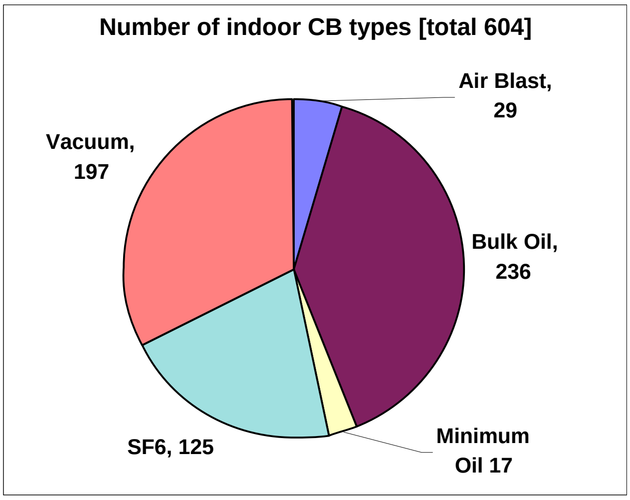


Figure 3-4: Indoor switchgear type profile



In general, 11 kV switchboards supplied before the 1960s incorporate compound-insulated busbars and heavy oil-insulated current transformer chambers and cable boxes. This generation of switchboard typically includes withdrawable bulk oil circuit breakers. There are increasing maintenance difficulties with some of this equipment, and a lack of spares. Some of these switchboards also show signs of partial discharge. Their reliability is an issue because of ageing insulation, and compound and oil leakage. There have been some catastrophic failures of this generation of equipment in Australia.

Recent studies on the potential for serious harm resulting from arc flash incidents at indoor switchboards show that, at some sites, the combination of high fault current and relatively long fault clearance times gives rise to the possibility of a very high arc fault hazard. New requirements for personal protective equipment have been issued for work at all sites where there is potential for a significant arc fault hazard.

ACTION

Both invasive and non-invasive condition-monitoring tests are carried out periodically on switchboards over 35 years of age to monitor insulation deterioration indicated by partial discharge activity or increased power factor. Where tests indicate insulation deterioration above acceptable limits, more frequent monitoring is carried out until the equipment is either repaired or replaced.

Aged compound-insulated switchboards are programmed for more intensive condition monitoring to identify the priorities for replacement. Because invasive testing of current transformer chambers and cable boxes is not always practicable, deterioration is indicated by compound leakage, increased temperatures and increased partial discharge activity.

Refurbishing aged compound-filled metal-clad switchboards to extend their original economic life has been shown to be uneconomic.

It is possible to retrofit SF_6 or vacuum circuit breakers in place of some older oil circuit breakers with air insulated busbars. This practice has been applied overseas where a large population of oil circuit breaker switchboards cannot be replaced immediately. It improves the reliability and reduces maintenance costs. This option will be evaluated for Transpower switchboards on a case-by-case basis, taking into account the overall switchboard condition and economic analysis.

Indoor switchboards are reviewed for possible replacement after a 45-year life, or when condition assessment tests indicate insulation deterioration above acceptable limits. Replacement programmes for indoor switchboards usually require close co-operation with customers, and may be co-ordinated with other customer-related network developments.

Replacement options at small substations may include lower-cost alternatives such as reclosers or ring-main units, which have been successfully used in specific situations.

At one site with very high potential arc fault hazard, an arc fault detection system has been installed to help mitigate risk. Replacement and new indoor switchboard installations will be specified to comply with the latest standards for arc fault containment.

3.2.4 Disconnectors

STATUS

There are over 4,500 disconnectors and over 1,400 earth switches in the network, with six different basic types from 33 to 220 kV:

- single side break-type disconnector and earth switch, 50 kV to 110 kV
- double side break-type disconnector and earth switch, 11 kV to 220 kV
- centre break-type disconnector and earth switch, 110 kV & 220 kV
- rocking post-type disconnector and earth switch, 33 kV
- vertical break-type disconnector and earth switch, 66 kV to 220 kV
- pantograph-type disconnector, 220 kV.

A breakdown of the population is shown in Table 3-4 below:

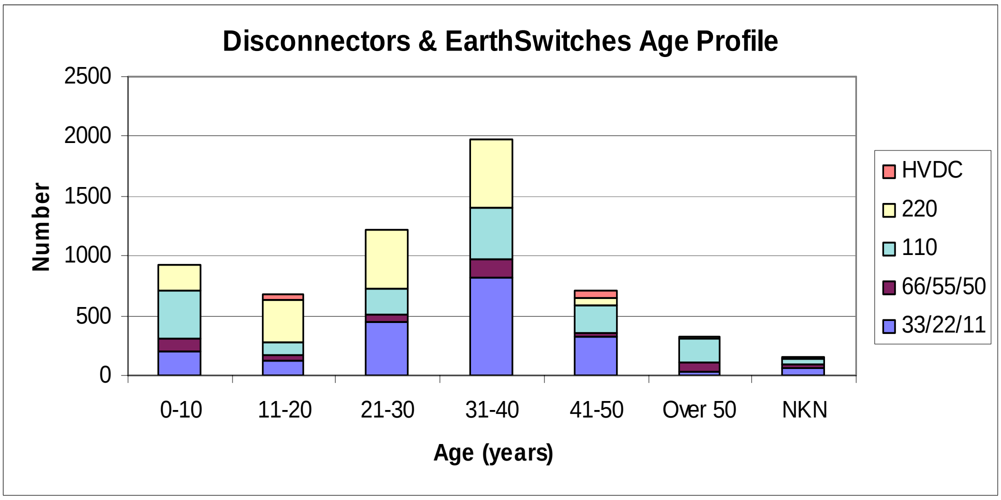
Table 3-4: Number of disconnectors and earth switches by voltage

	220	110	66	50	33	22	16	11	HVDC	Total
Disconnectors	1274	1284	349	30	1401	19	15	134	51	4557
Earth switches	452	375	89	4	364	17		77	60	1438
Total	1726	1659	438	34	1765	36	15	211	111	5995

Note: 55 kV included with 66 kV. HVDC includes all voltages, AC and DC.

The age profile of the disconnector population is shown in Figure 3-5.

Figure 3-5: Disconnector and earth switch age profile



Transpower's disconnector and earth switch population has an average age of 28 years.

All 220 kV disconnectors are post mounted. The most common types are vertical break and centre-rotating double break. Pantograph types were used to a limited extent in the early 1990s for special bus designs. Centre break designs have been trialled both at 220 and 110 kV.

The centre rotating double break and vertical break designs are preferred for New Zealand conditions, taking into account seismic withstand requirements and typical conductor sizes.

Earlier gantry-mounted 66 & 110 kV designs, particularly single side break types, depend on correct setting up and alignment. Due to their design, they are exposed to partially open contacts and hotspots, particularly following minor earthquakes. Correct maintenance and contact preparation is required for ongoing reliability. These designs were generally limited to 1600 A and a significant proportion of the population is rated at only 800 A. At a number of sites, these older disconnectors have been replaced so they do not become the limit in the thermal chain as load increases.

Disconnector and earth switch rationalisation in the 110 and 66 kV systems has led to a small reduction in the population with consequential savings in maintenance and operational costs.

ACTION

All disconnectors are monitored by annual thermo-vision checks and monthly visual inspections. The standard interval for servicing disconnectors and earth switches is four years, but modern disconnector types, incorporating sealed bearings and improved contact arrangements, are only checked for functionality at this interval.

Disconnectors and earth switches over 50 years old have typically not been type-tested to prove current or fault ratings. These unrated disconnectors and earth switches have been progressively replaced where their estimated operational limits have been reached.

Other disconnectors and earth switches programmed for replacement are generally older designs, where there are increasing maintenance costs, unavailability of spares, poor condition assessment results and increasing unreliability or where the assigned rating is exceeded.

The forecast programme of disconnector and earth switch replacement is as follows:

Table 3-5: Forecast disconnector replacement programme

All Regions	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17
220 kV	1	6	12	14	4	4			1
110 kV	9	6	16	11	14	37	25	23	33
66 kV	7	4	15	4	4	5	22	21	8
50 kV									
33 kV			7	1		9	11	11	5
Total	**17**	**14**	**50**	**30**	**22**	**55**	**58**	**55**	**47**

Table 3-6: Forecast earth switch replacement programme

All Regions	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17
220 kV		1	1					1	
110 kV	4	2		3	4		1	2	6
66 kV	1							2	2
33 kV	4	2	13					40	
Total	**9**	**5**	**14**	**3**	**4**		**1**	**45**	**8**

3.2.5 Power transformers

STATUS

Transpower has an in-service population of 1,116 single-phase and three-phase power transformers of various functions and voltages as shown in Table 3-7:

Table 3-7: Number of power transformers – types and primary voltages

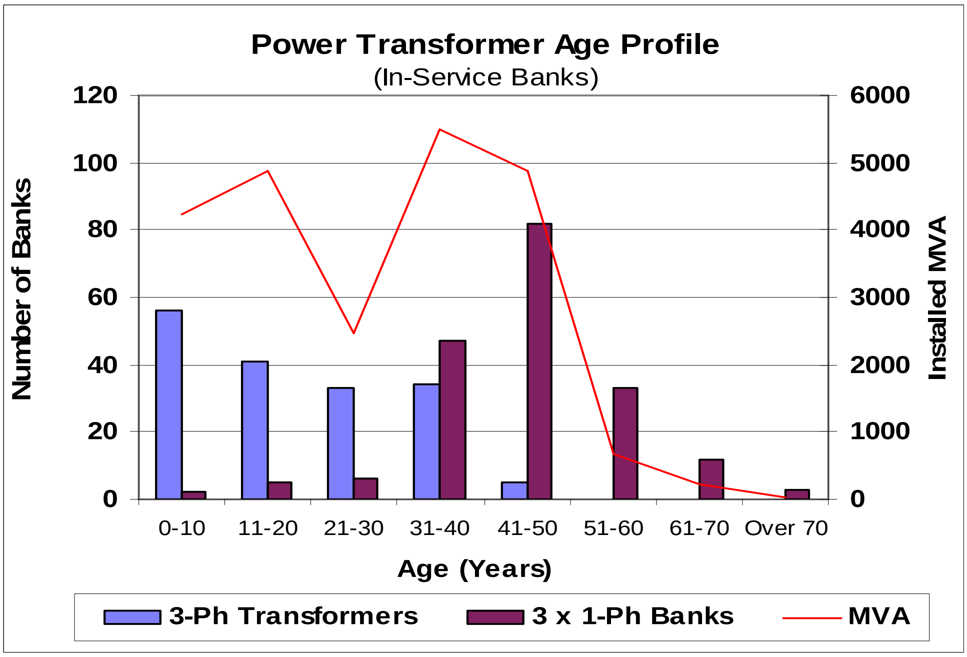
kV	220	110	66	50	33	22	16	11	3.3	Total
Power transformers										
Supply - 3-ph units	49	70	16	3	10					148
Supply - 1-ph units	54	303	51	3	3					414
HVDC Converter 1-ph units	6	18								30
Interconnector – 3-ph units	20	1								21
Interconnector – 3x1-ph units	87	15								102
Traction - 2-ph units	16									16
Total in-service units	**232**	**407**	**67**	**6**	**13**					**725**
Spare single-phase units	21	57	10	1	1					90
Spare HVDC converter (1-ph)	2	4								6
Miscellaneous transformers										
Local Service	3		1		96	3		86	6	195
Earthing			2		34	15	1	43		95
Regulator (3-ph)								5		5
Total										**1116**

Fifty per cent of the in-service banks are three-phase units. The age profile of the transformers (both single-phase and three-phase) is shown in Table 3-8 and Figure 3-6.

Table 3-8: In-service power transformers age profile

	Power transformers					Misc. transformers	
Years	Supply	Inter-connecting	Converter (HVDC)	Traction 2-ph	Local service	Earthing	Regulating
0-10	49	7		2	22	19	
11-20	35	10	6	2	19	30	
21-30	36	4		4	41	42	
31-40	140	34			45	6	
41-50	192	35	24		43	8	1
51-60	77	21			15	2	1
61-70	27	9			4		3
Over 70	6	3			2		
Avg Age	**38.9**	**40.8**	**38.4**	**15.9**	**31**	**20.7**	**61.2**
Subtotal (<50 yrs)	452	90	30	8	170	105	1
Subtotal (50+ yrs)	110	33	0	0	21	2	4
Total	**562**	**123**	**30**	**8**	**191**	**107**	**5**

Figure 3-6: Power transformer age profile



The average age of power and miscellaneous transformers has increased since the report in 2005. The average ages are now 39.8 years and 27 years respectively, compared with 38.6 years and 29 years respectively as reported in 2005.

The transformer population consists of a very wide range of voltage levels, ratings and manufacturers, with only very small populations of identical units and limited interchangeability.

Despite a recent increase in the number of new transformer installations, and the replacement and scrapping of many old and under rated transformers, the average age continues to increase. A benchmarking survey carried out with other utilities in 2007 through the ITOMS group showed that Transpower's power transformer population has an average age several years older than that of the average of the other survey participants. The proportion of major power transformers older than 50 years has increased from 17.6% in 2005, to 19.8% in 2007.

As system loadings increase, the average loading on many of the older transformers is also increasing. Many of these older units are now exposed to the highest loadings experienced in their lifetime, particularly during planned outages of parallel transformers. Increasing attention to condition monitoring is required to manage the risk of transformer failure.

Recent major failures

Benchmark information from the United States and elsewhere suggests that an increase in the rate of serious transformer failures must be expected as the overall population ages, notwithstanding the effect of increasing loadings.

Historically, Transpower has experienced a relatively low rate of major failures of power transformers. However, since 2004, a number of mid-life transformers have suffered major winding failures with little or no prior warning:

Rating	Three phase/single phase	Function	Manufactured	Outcome
220/33 kV, 100 MVA	Three phase	Supply	1981	Winding repaired
220/33 kV, 60 MVA	Three phase	Supply	1985	Winding repaired
220/33 kV, 33.3 MVA	Single phase	Supply	1972	Tank damaged, windings destroyed, transformer written off
220/110/14 kV, 141 MVA	Three phase	Interconnecting	1966	Windings destroyed, transformer written off
110/11 kV, 40 MVA	Three phase	Supply	1996	Winding replacement under investigation

In two cases, the transformer was damaged beyond repair. Recovery from transformer winding failures can take 18 months or more, using either a repair or replacement method.

The increasing population of three phase power transformers at both 220 kV and 110 kV has significantly increased the risk exposure for transformer unit failure. Older installations of single phase transformers usually had a single phase operational spare located on site. This spare can be placed in service relatively quickly in the event of a failure of an in-service unit. However, the installation of relatively large three phase transformers creates an increasing risk of a potentially high impact failure with a long recovery time, because there are currently no spare three phase transformers.

There are very few surplus banks of single phase transformers. These surplus banks are generally of small rating, and cannot cover the loss of a large three phase transformer. It could take 18 months or more to recover from a major winding failure of a large three phase transformer.

ACTION

Refurbishment and repairs

A major refurbishment programme of selected power transformers has been under way since 1996, to address known weaknesses in certain makes and models of transformer and prevent premature failure. Transpower has carried out over 250 power transformer refurbishments, almost all on single-phase units.

This work is generally only carried out where refurbishment is economic compared with replacement, taking into account the remaining life of the transformer before projected load growth would necessitate replacement.

The outlook is for a declining volume of work in transformer refurbishment, given the increasing age of the single phase transformer population, and the operational difficulties associated with attempting major refurbishment of three phase transformers.

Some major repairs of failed transformers have been completed with local resources.

Replacement

Relatively few major power transformers are replaced on the grounds of condition. Almost all replacements occur because the transformer is either of insufficient capacity to meet increasing load, or the entire point of supply has been replaced by other network developments.

Since establishment in 1987, Transpower has on average purchased five new power transformers a year. However, this has increased to nine each year for the last two years because of increasing load growth. The rate of new installations is expected to be nine to 12 units a year for the next five years. New power transformers are normally three-phase transformers because of reduced capital and maintenance costs.

Spares provision

Analysis of the risk associated with the increasing population of three phase transformers nationwide has demonstrated the need for additional spare transformers, so that security can be restored within a reasonable period in the event of a major failure. It is planned to procure at least 10 strategic spare power transformers to provide a means of promptly restoring security following a major failure. The first priority is to provide cover for the fleet of 220/33 kV and 110/33 kV three phase transformers. Given the wide range of voltage ratios, ratings and physical configurations in the existing population, the strategic spare transformers will be selected as a compromise that will provide cover for as many existing sites as possible.

3.2.6 Instrument transformers

STATUS

Transpower has over 7,000 instrument transformers in service at AC stations. Of these, 5,269 are standalone units, with the rest integral with metal-clad and gas insulated switchgear and ‘dead tank’ circuit-breakers.

The number of freestanding instrument transformers has dropped markedly in recent years because of significant system changes, with decommissioning of several substations and the replacement of outdoor switchgear with indoor switchboards.

The age profile of instrument transformers is shown in Table 3-9.

The average age of Transpower’s standalone instrument transformer population has steadily dropped to 17 years largely because of a drive to replace defective, aged and suspect units, but also because a number of older stations and plant have been decommissioned. Overseas authorities estimate the life of an instrument transformer to be between 25 and 35 years. However, Transpower’s experience, as supported by surveys, is that well-designed and well-built instrument transformers can last considerably longer.

Table 3-9: AC stations freestanding instrument transformers age profile

Type	**System Voltage (kV)**							**Total**	**Average age years**
	220	**110**	**66**	**55-50**	**33**	**22**	**11**		
Capacitive VT	745	112						857	17.0
Coupling capacitors CC		44	19					63	20
Magnetic VT	1	472	124	34	397	3	43	1074	16.4
Current CT	1287	1219	246	27	364	3	123	3269	18.2
Metering CT/VT							6	6	6
TOTAL	2,033	1,847	389	61	761	6	172	5,269	17

Many of the older instrument transformers suffer from age-related defects and it is generally more cost effective and lower risk to replace an instrument transformer than to repair or recondition it.

ACTION

Maintenance is driven by periodic inspections and testing. A few units are refurbished or repaired each year as they meet particular condition, economic and operational criteria.

Following two in-service failures, a replacement programme has started for a small batch of identical 110 kV current transformers with known generic defects. There is a small on-going programme for replacing other aged and deteriorated instrument transformers. In the case of coupling capacitors, a significant number of these are to be decommissioned following the roll out of a fibre optic/wireless communications network.

3.2.7 Capacitor banks

STATUS

Transpower has 124 capacitor banks in a range of configurations and voltages. This includes all the HVDC banks as well as the individual banks of the harmonic filters. The capacitor banks on the AC system are usually used for reactive support (var compensation) and voltage stability. The remainder are for harmonic filtering, voltage suppression or damping of the HVDC link.

Table 3-10: Capacitor banks by type and system voltage

Type	**System Voltage (kV)**								**Total**
	350	**270**	**220**	**110**	**66**	**33**	**12-24**	**<12**	
Reactive power source			10	10	4	9	0	24	57
Filter element	10	4	10	2		2	2	5	35
Damping		8					1	9	18
Surge suppression		4					8	2	14
Total	**10**	**16**	**20**	**12**	**3**	**11**	**11**	**40**	**124**
Notes:									
Harmonic filters contain capacitor banks and reactors.									

The nominal design life of a capacitor bank is 25 years. Transpower's capacitor bank profile has an average age of 20 years, with 15 banks at 42 years old. Eleven of the older banks have been upgraded with new capacitors since 1990.

Transpower's capacitor failure rate is 0.1 to 0.3 per cent per year, which is comparable to the manufacturer's quoted failure rate.

The older HVDC filter bank capacitors are deteriorating but with replacements, sealing of leaks around their bushings and improving the flexibility of the HV connections, the numbers of forced outages at both HVDC stations has been reduced.

From 2005 to mid 2007 the following capacitor banks have been installed to provide additional reactive support

- 3 x 220 kV Islington 70 MVAr each and Albany 100 MVAr
- 5 x 110 kV Hepburn Rd, Penrose and Bombay 60 MVAr each
- 1 x 66 kV Southbrook 34 MVAr
- 4 x 33 kV Stoke 11 MVAr each.

ACTION

The capacitor bank condition is continuously monitored by out-of-balance or earth-leakage systems. Following an alarm or tripping, each individual capacitor is tested and faulty units replaced.

The HVDC Pole 1 filter bank capacitors are inspected at least twice yearly to replace or repair leaking capacitors. Because of the very large number of capacitors and their high cost, it is more cost effective to replace the capacitor units as they fail rather than replace the complete bank.

Capacitor bank spares level is set at two to four per cent based on the average reliability and lead time for replacements. There is often a need to replace more than just the failed capacitors to rebalance the bank.

3.2.8 Static Var Compensator

STATUS

Transpower has two static var compensator (SVC). The first was installed at Islington in 1997 and operates at 11 kV. A second SVC was commissioned at the Albany substation in early 2008.

ACTION

Scheduled maintenance is planned to continue.

3.2.9 Synchronous condensers

STATUS

Transpower has 10 synchronous condensers, all operating at 11 kV. Six of the units, located at the Haywards HVDC stations, are hydrogen-cooled.

The synchronous condensers vary in age from 42 to 53 years, with an average age of 47 years.

The Haywards synchronous condensers provide dynamic voltage support for the Wellington region, and are essential to the operation of the HVDC link.

Table 3-11: Synchronous condensers by rating

Substation	**System Rating in Mvar**				**Total**
	65	**60**	**35**	**30**	
Haywards	4	2	2		8
Islington				2	2
Total	**4**	**2**	**2**	**2**	**10**

The Haywards condensers C1 and C2 were among the last to be made using bitumen-impregnated mica insulation in the stator windings. This insulation system is prone to developing voids, eventually leading to failure. However, the C1 and C2 machines operate in a pressurised hydrogen gas environment, which mitigates any partial discharges across voids within the insulation. Operation in hydrogen will greatly increase the useful life of the winding insulation compared with operation in air.

Haywards condensers C3 and C4 have suffered from major failures of the pony motor used to bring the machine up to synchronous speed during start-up. The root cause of the problem is a design deficiency with the slipring and brushgear arrangements of the pony motor.

All the Haywards synchronous condenser units were substantially refurbished in the early 1990s, including removal of the rotor from the stator to permit re-wedging of the stator bars in the slots of the stator core. Condensers C3 and C4 were fitted with new stator windings and re-insulated rotor coils. All machines were provided with new static excitation and control systems, and new cooling towers and pumps. The hydrogen-cooled machines (C1, C2 and C7-C10) were fitted with complete replacement gas management and monitoring equipment, and a new centralised hydrogen and carbon dioxide gas facility was established.

There is some movement of the building foundations supporting the Haywards condensers C7 to C10 which, while not appearing critical, is being monitored.

In December 2007, the Transpower Board decided to partially decommission the HVDC Pole 1 Converter stations. At Haywards, the synchronous condensers C7-C10 are connected to the network via the tertiary windings of the Pole 1 converter transformers T7-T10. The Pole 1 converter transformers will be decommissioned within the next few years.

However, there is continuing requirement for the Haywards condensers C7-C10 to support Wellington region voltage and the operation of the HVDC link. This means that new unit transformers will be required to reconnect these synchronous condensers to the 110 kV network.

The two Islington synchronous condensers are used as backup for the Islington SVC. The main machines are of robust construction. Their control systems and switchgear are in poor condition. Major refurbishment and replacement will be needed if these machines are to be maintained in reliable condition into the future. A strategic review is being carried out to determine the future of these machines.

ACTION

A major review of asset management plans for the 8 Haywards synchronous condensers is in progress. This will examine the investment in replacement auxiliary, protection and control systems and major overhauls that will be needed to provide another 20 years or more of reliable service from these machines.

A review of hydrogen safety is also in progress as part of the overall asset management plan review.

The continuing operational requirements for the Haywards condensers C7-C10 means that new unit transformers will be required to reconnect the synchronous condensers to the 110 kV network after the Pole 1 converter transformers are decommissioned. These new unit transformers will be new three phase transformers of smaller rating than the existing converter transformers.

The installation of new unit transformers for the Haywards synchronous condensers C7-C10 will provide an opportunity to provide fire separation between each transformer. Lengthy outages of each condensers will be required for this work. These outages will be used to facilitate the major overhaul program for each machine.

A project is planned for retrofitting brush-lifting equipment to the pony motors of Haywards C3 and C4.

Future requirements for the Islington synchronous condensers will be reviewed, and provision made for a major refurbishment if a significant life extension is required.

3.2.10 HV reactors

STATUS

Transpower has 377 reactors of air-cored and oil filled construction, associated with AC and HVDC substations. These reactors provide a wide range of functions including reactive support, fault current limiting, harmonic filtering, inrush protection as an integral part of capacitor banks, and transient suppression and damping functions for the HVDC link.

Table 3-12: High voltage reactors by system and voltage

AC system reactors								**Total**
kV	Neutral	11	22	33	66	110	220	
Quantity	2	120	1	3	13	21	26	186
HVDC system reactors								
HVDC Pole		Pole 1		Pole 2		Electrode line		
Quantity		113		44		3		160

Almost all of the AC system reactors are air-cored units. Most of these are in service in capacitor banks installed since 1980. They are very reliable and need little maintenance. Most dry-type reactors are in very good condition. However, the reactors in seven 11 kV capacitor banks installed in 1983 in the Auckland region have suffered accelerated deterioration of insulation, caused by overheating throughout the years in service.

The reactors in the HVDC Pole 2 system are all air-cored. They were commissioned in 1991 and are in good condition. The reactors in the Pole 1 system are a mixture of oil-immersed and air-cored types, and were all commissioned in 1965. Many of the oil-immersed types are seismically vulnerable and have no spares or modern equivalent. The forced oil cooling systems are increasingly maintenance intensive with oil leaks and corrosion problems.

ACTION

The deteriorated reactors in the Auckland region 11 kV capacitor banks are expected to be retired over the next 10 years as the existing capacitor banks are progressively replaced at new locations. The future of the reactors in the HVDC Pole 1 system is linked with the strategy for the retirement or replacement of the Pole 1 HVDC Converter Stations.

3.2.11 AC power cables

STATUS

Most of Transpower's high-voltage power cables are rated at 33 kV and 11 kV. Older cables are of paper insulated lead sheathed (PILC) construction. However, since the mid-1970s, all new and replacement cables of these ratings have used cross-linked polyethylene (XLPE) insulation, with thermo-fit terminations. This type of cable now constitutes more than half the total population. The cables are of relatively short lengths (most less than 200 m long) and are laid either directly in the ground or in ducts.

Transpower also has a small number of pressurised oil-filled 220 and 110 kV cables, installed at four stations between 1973 and 1983.

Table 3-13: Number of HVAC power cables by type and voltage

Insulating material	**Voltage (kV)**								
	220	**110**	**66**	**50**	**33**	**22**	**11**	**3.3**	**Total**
Paper, Oil under gas pressure	8								8
Paper, oil impregnated	6	3			17	3	122		151
XLPE	5	21	4	2	216	5	199		452
Other	4	5			97		69	7	182
Total	**23**	**29**	**4**	**2**	**330**	**8**	**390**	**7**	**793**

Most of the cables are in good condition but some older PILC cables have failed because the lead sheaths have cracked allowing moisture to enter, while a few of the XLPE terminations have failed because of poor workmanship.

Transpower's pressurised oil-filled 220 and 110 kV cables are generally in good condition. Historical problems with corrosion, oil leaks in the gland, and chafing of the outer sheaths have been addressed or require more intensive maintenance to mitigate risks. There are no plans to replace these within the 10-year planning period.

Transpower's XLPE AC cables have been installed over the last 20 years, are 110 kV and form part of transmission circuits. They are all XLPE, less than 2.4 km long, and less than 20 years old. An increasing number of cables are being installed to place short sections of overhead transmission line underground.

ACTION

Aged PILC cables with a history of failures, cracked lead sheaths or leaking compound-filled cable terminations are scheduled for replacement.

A number of older PILC cables will be replaced as part of planned indoor switchboard replacement projects.

Fibre optic systems that provide the facility for distributed temperature monitoring will be installed with all new 220 kV, 110 kV and 66 kV cables installed in transmission circuits. This facility will enable monitoring of the cable condition and management of loadings, if required, at intervals throughout the life of the cable. The condition of the existing 220 kV and 110 kV cables is being reviewed and temperature indicators will be fitted as necessary.

3.2.12 Structures and buswork

A variety of substation structural systems, outdoor electrical busbars and substation high-voltage insulators are in service, reflecting design standards applied over the past 80 years.

Structures

STATUS

Various types of substation structures are in service as shown Table 3-14.

Most substations have galvanised steel lattice structures. Many older structures at stations near the coast and in industrial and geothermal areas require corrosion repairs to preserve and extend their life.

Aluminium lattice structures are found at a few substations. Their condition is generally good, but they are prone to distortion if the strung bus is replaced with larger conductor or heavier disconnectors to achieve an up-rating of the busbar.

Table 3-14: Substation structural support systems

Structure type	Structure use/age
Aluminium lattice structures	Strung busbars, disconnectors, and line terminations pre-1970
Galvanised steel lattice structures	Strung busbars, disconnectors, pre-1985 (still used for new line terminations)
Reinforced concrete posts	Tubular conductor busbar supports, disconnectors, earth switches, instrument transformers from the 1960s to 1985
Galvanised Steel posts (tubular or RHS)	Tubular conductor busbar supports, disconnectors earth switches, instrument transformers since 1985 (new line terminations since 1990)
Wood poles	A few older substations, mostly rural

Reinforced concrete posts installed in 1960s are deteriorating at many sites, and reinforcing steel is rusting, causing posts to crack or spall. As the posts continue to age, this problem will become more serious.

Galvanised steel posts are generally in good condition. However, the performance of the grouting under the post base plates has often proved unsatisfactory. Grout shrinkage lets water in, resulting in corrosion of the base plate and holding-down bolts.

There is likely to be an increasing need for remedial works, life extension and partial replacement of substation structural elements over the next 10 years.

ACTION

Repairs are undertaken on steel lattice gantry structures to preserve and extend their life. These repairs may include application of protective coatings, and replacement of corroded fasteners and selected gantry members.

For concrete post structures, investigations will continue into the most appropriate condition assessment regimes and economic life extension measures. Replacements of small numbers of badly deteriorated posts are planned at several sites.

Remedial work is planned for a small number of galvanised steel posts affected by grout shrinkage and corrosion of the base plates.

Busbar systems

STATUS

Various types of substation busbar systems are in service, as shown in Table 3-15.

Table 3-15: Substation busbar systems

Busbar type	Busbar use/age
Flexible stranded conductor strung busbars (copper)	Older substations
Flexible hollow core conductor strung busbars (copper)	Older substations
Tubular conductor supported busbars (copper)	1960s-1970s substations
Flexible stranded conductor strung busbars (aluminium alloy)	1980s-1990s substations
Tubular conductor supported busbars (aluminium alloy)	1980s-1990s substations

ACTION

Flexible hollow core copper conductor has been systematically replaced at many substations. However, this policy has now been moderated to periodic visual inspections and annual thermographic surveys, with replacement based on condition. Where new or refurbished equipment is installed, the flexible hollow core and stranded copper is replaced with flexible aluminium. This reduces bimetallic corrosion and the mechanical loading imposed on the terminals of electrical equipment.

A small number of replacement projects are planned for conductors that are deteriorated or where technically deficient insulators and hardware are identified.

Substation insulators

STATUS

The main types of substation insulators in service are shown in Table 3:16.

Table 3-16: Substation insulators

Insulator type	Insulator use/age
Cap-and-pin insulators	Busbar support and disconnectors pre-1980 – at 33 kV, this type was used up to 2000
Porcelain disc insulators	Strung bus pre-1970
Glass disc insulators	Strung bus post-1970
Solid core porcelain post insulators	Busbar support and disconnectors since mid-1980s
Composite long rod insulators	Strung bus in highly contaminated areas since late-1990s

Ageing cap-and-pin insulators are susceptible to pin stem corrosion inside the porcelain cap, eventually leading to the porcelain cracking. The 33 kV cap and pin type suffers from mechanical failures caused by the expansion/contraction over time of the different materials, ie, porcelain, cement and the metalwork. These have become a priority for replacement.

ACTION

Busbar insulator replacement projects are planned at seven sites over the next 10 years.

Overhead earthwires

Following the Otahuhu substation earthwire failure of 12 June 2006, a nationwide risk management for overhead earthwires was completed. The initiatives include:

- inspecting all transmission line earthwire terminations at substations
- a condition assessment of all substation earthwires
- bonding to earth of all substation earthwires and transmission terminal span earthwires
- a review of the overhead earthwire lightning protection for all high priority substations where an earthwire failure would create a major system event. Alternative design options for lightning protection are explored as appropriate.

Structure rationalisation

Rationalisations at some stations will achieve significant savings in maintenance cost as well as improving reliability and availability, eg, removal of the top bus from a number of double layer structures in service at 66 kV and 110 kV.

Analysis of the performance of outdoor 33 kV structures shows significant operational performance, safety and maintenance cost drivers for the conversion of larger outdoor switchyards to indoor switchboards. Case-by-case studies will establish the viability of such conversions at each site, and to identify the most appropriate timing for such projects.

3.2.13 Buildings and grounds

STATUS

A recent marked increase in break-ins and theft has led to a review of the physical security of substations, as an important health and safety and system security initiative.

Improved temperature regulation is needed in many substation control buildings to help maintain the life and performance of valve-regulated lead acid batteries, and to minimise long-term risk to electronic relays and equipment caused by thermal cycling and extended periods at high temperatures. Most existing buildings are unventilated, and face problems with solar gain and the heat generated by the electrical equipment.

Transpower has a programme for mitigating oil spill risks at substations. A risk management methodology is used to determine the appropriate oil spill mitigation for each site. This work has been largely completed at most sites, with a small number of upgrade projects still planned.

ACTION

The key design objective for substation physical security is to prevent unauthorised people from entering high-voltage switchyards, and to at least delay determined intruders. At sites with a higher risk profile, electric powered fences will be added to the existing chain link mesh fence. Attention is being paid to the integrity of substation switchyard fences and gate structures. A new design of switchyard fencing has been developed for all new and replacement switchyard fence projects. Condition- and risk-based criteria are used for determining priorities for substation fence upgrade and replacement.

Safety reviews of substation earthing are carried out regularly. Modelling studies of earthgrid performance are backed up by current injection tests to identify any potentially hazardous step-and-touch voltages around the perimeter of the site. Mitigation of identified hazards typically includes installing buried gradient control conductors, providing ground surface insulating layers, and installing short sections of wooden fencing.

There is an ongoing initiative to obtain sustainable savings from routine maintenance of buildings and grounds. Improvements in the cost efficiency of facilities management will be obtained by converting some existing mowed lawn areas at substations to stock grazing, and removing high maintenance cost hedges and plantings where appropriate. Improved condition assessment and prioritisation techniques will be applied to improve cost efficiencies in maintaining exterior painting of buildings and the upkeep of substation roads.

3.3 AC substations secondary equipment

The AC substations secondary equipment asset class consists of all protection and control assets and equipment including relays, protection schemes, as well as auxiliary equipment including AVRs and battery power supply systems. Metering and telecommunications and IT assets are covered in separate sections.

Until the early 1980s, a typical 220 kV protection scheme consisted of a single electromechanical distance relay and directional earth fault relay. Enhancement on the 220 kV grid, starting in the early 1980s, added a second line protection to work alongside these single-distance relay schemes.

In the late 1990s, a policy programme was implemented to replace the ageing electromechanical relays, many over 30 years old, because they had started showing signs of failure. The last of the 220kV electromechanical relays was replaced in 2004.

On the 220 kV transmission circuits, protection schemes now have duplicate relays based on either analogue semiconductor or numerical technology.

On the 110 kV and 66 kV sub-transmission networks, all electromechanical distance relays have been replaced as part of a replacement programme that started in 1996.

Figure 3-7: Distance relay age profile

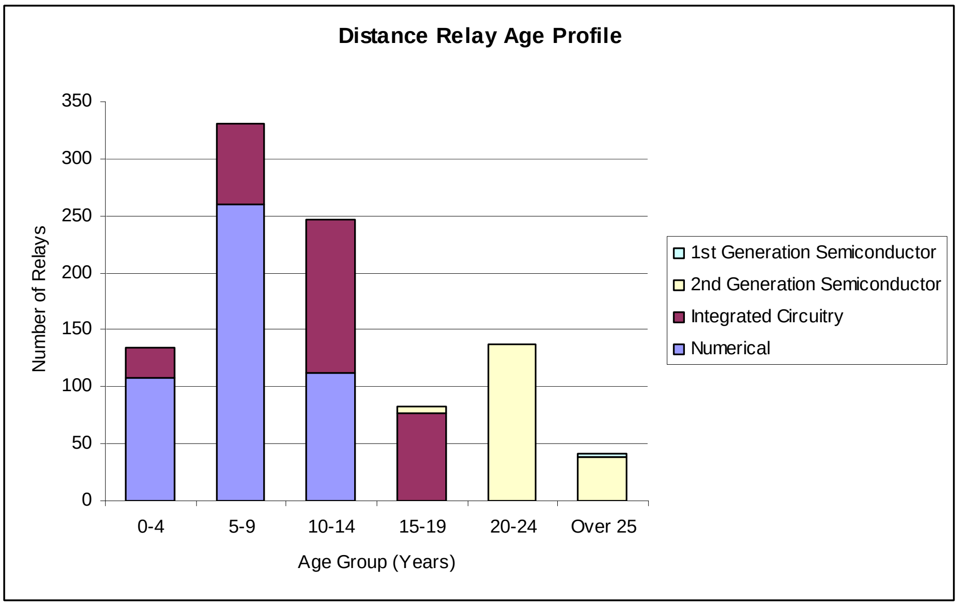


Table 3-17: Technology versus age

Technology versus age		Expected Life
33 - 46 years	Electromechanical	30 – 45 years
27 -32 years	First generation semiconductor (discrete components)	20 – 25 years
19 -26 years	Second generation semiconductor (discrete components)	20 – 25 years
0 -18 years	Integrated circuitry	20 – 25 years
0 -13 years	Numerical (microprocessor based)	15 – 20 years

3.3.1 Protection and control – relays

STATUS

While electromechanical relays have been proven in service to last more than 30 years, the next generation of relays manufactured using discrete semiconductor components are likely to have lives averaging 25 years. Close monitoring of the relays using this technology has shown that, while the relays continue to perform well, there are now issues over their age and their use in complex schemes that require stability in failure modes.

The next phase of replacements has begun with the small number of relays with first-generation discrete component semiconductor technology, for which there is no longer any expertise or maintenance spares. Replacement of the second-generation semiconductor discrete component relays is being investigated. Replacement has begun on relays that are not compliant with the EGR requirements for 220kV duplication. All discrete component relays are expected to be replaced by 2012.

ACTION

The last electromechanical distance relays are scheduled to be replaced with modern relays within the next year. Semiconductor relays with discrete components will continue to be monitored but plans will be made to start replacing the older relays and those on important lines which have simple blocking.

3.3.2 Protection and control – protection schemes

STATUS

Since the early 1980s, busbar, circuit breaker fail and duplicate protections have been installed at 220 kV installations as part of a protection upgrade programme. Fitting these protections may be required where:

- existing backup protections are slow, non-existent or do not meet statutory or safety criteria
- unacceptable system disruption may result from relay failure.

Installation has already started at a number of key 110kV substations and those that need to be upgraded should be completed by 2012.

There is insufficient failure data to justify a scheduled transformer protection replacement. While there is no scheduled programme, if the existing protection is shown to be unreliable or functionally inadequate it is upgraded to the required standard or replaced. Factors for deciding to upgrade or replace include the presence of capacitors with PCBs, lack of spares, and opportunities associated with economies of scale, eg, the installation of another bank.

Over the last five years a major replacement of protection occurred with a feeder remote control project. Numerical relays are used for all new switchgear installations and relay replacements, and are integrated into SCADA and local metering and control. Over 80 per cent of feeder protections are now numerical. Performance of the remaining electromechanical and semiconductor relays is being closely monitored. As with transformer protections, relays will be upgraded once they are shown to be unreliable or functionally inadequate.

Local control and alarm panels are no longer being installed. With each protection replacement and upgrade, local control and indication is being migrated to protection panels. Local alarms are provided by data displays in SCADA RTU panels. In some substations, local control and alarms are provided by man-machine interface VDUs of Substation Control Systems. When all secondary cabling has been re-routed, the control and alarms panels are then removed. The remaining control and alarm panels in Transpower's substations are expected to be removed within 10 years, as the associated numerical protection installations are made.

Over the last 10 years, ageing disturbance recorders have been replaced by microprocessor-based equipment at important locations. These improve fault diagnostics and provide quality of supply monitoring facilities and remote download of information. Numerical relays also capture limited disturbance information. With the increase in the number of numerical relays the need for the number of dedicated disturbance recorder was reconsidered. In 2004 all remaining electromechanical oscilloperturbographs were decommissioned without being replaced.

ACTION

Ageing transformer protection is being replaced with transformer management relays in conjunction with development projects or busbar and circuit breaker failure protection installations. Transformer protection relays with PCBs are scheduled to be replaced within seven years as agreed with the Ministry of Health.

Ageing feeder protection is being replaced with feeder management relays, as part of switchboard replacements.

3.3.3 Protection and control – future direction

Numerical or digital technology has made it possible to integrate a large number of functions – protection, control and measurement – in one unit. Design and installation costs, hardware and panel space requirements have reduced as a result.

Digital equipment needs less lifetime testing and maintenance, resulting in maintenance savings. In line with the repair philosophy of digital equipment, maintenance and equipment spares policies have been revised to enable replacement of whole units when equipment fails.

Protection and SCADA are expected to continue integrating. Manufacturers are now making more relays that use IEC 61850 "Communication networks and systems in substations". IEC 61850 is expected to enable greater compatibility and easier interconnection of different manufacturers' relays into protection and control systems. The interconnection of relays using IEC 61850 and Ethernet ports, together with high-speed communications to substations, will permit remote engineering access to fault records, transient recordings and synchrophasors. Relays being bought now will be IEC 61850-compliant, with Ethernet ports suitable for fibre connection or at least upgradeable.

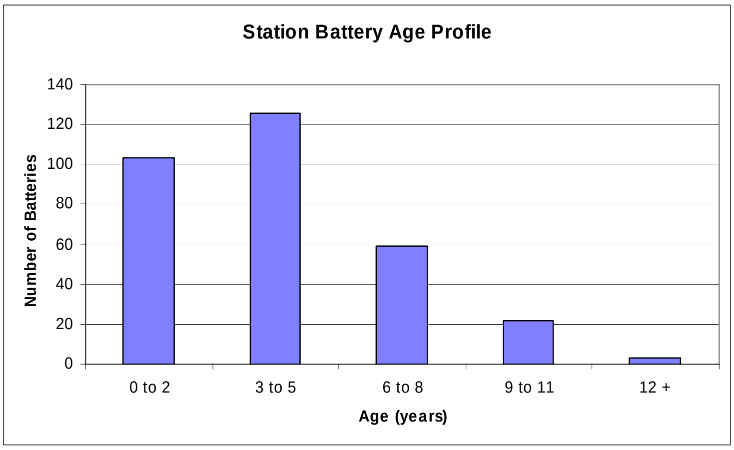
Fibre optic technology – used both as the communications interface and within instrument transformers – is expected to significantly affect future power system protection. However, the technology is still relatively new, with limited numbers of installations worldwide. The technology is likely to be further advanced and more widely accepted internationally over the next decade.

3.3.4 Station battery systems

STATUS

Transpower now requires dual station battery systems for all its substations. Dual battery systems have been installed at most 220 kV Transpower substations and are being installed at all others, prioritised according to the condition of existing system, upgrade work, degree of remote backup and consequence of failure of a single battery system during a fault.

Figure 3-8: Station battery age profile



The DC power supplies are essential to provide service continuity of the Transpower telecommunications network if mains power fails. Effective backup protection must be independent of the main protection, with no shared system or common failure modes. This independence also applies to the battery supplies. The failure of a battery system must not remove both the main and backup protections.

Transpower uses valve-regulated lead-acid (VRLA) batteries which need less routine maintenance. The VRLA batteries are also recombinant cells (which do not liberate large quantities of hydrogen) so do not need to be housed in special battery rooms with flameproof fixtures. At sites where batteries are installed in the yard the wet cell type will be retained. Battery chargers that have high output ripple voltage or do not compensate for battery temperature variations are being replaced. These shortcomings could prematurely reduce the life of VRLA batteries. Battery systems are identified for replacement after eight years' service and may be replaced sooner, depending on discharge test results.

ACTION

Over the last three to four years this replacement work has been consolidated as a single managed programme of work. Dual battery systems will progressively be installed at all remaining substations with all installation completed by 2011.

Transpower will continue modifying, where possible, or replacing unsuitable battery chargers.

3.4 Metering

Transpower is responsible for the supply and management of 392 Grid Exit Point (GXP) meters installed at 148 sites on the National Grid. These are a mixture of equipment that includes instrument transformers, data recorders and Quad 4 revenue meters. The existing Quad 4 meters were installed by Transpower in the mid 1990s as a prerequisite to the start of the wholesale market in 1996.

The Landys & Gyr FAF electronic data recorders were installed in the late 1980s and, combined with the changed metering arrangements in the 1990s, the need for summation current transformers was removed. The FAF data recorders are still important as they are used to calculate instantaneous total bus loads information that is provide to the distribution companies. The data recorders are also used to derive local service loads at some sites.

STATUS

The existing revenue metering equipment installed at grid exit points is a combination of equipment that includes CTs, data recorders and Quad 4 revenue meters.

The manufacturer stopped producing the Quad 4 meters about five years ago and second-hand meters are now difficult to obtain. Due to meter attrition and the need for additional meters (with the establishment of new grid investments), Transpower is likely to reach the end of its GXP meter supplies by the end of 2007.

The current practice for delivering dynamic metering information to connected parties is via hard-wire circuits for each parameter sent. As with Transpower, the connected parties are likely to want to manage the number of physical connections into the SCADA systems at their points of connection. This will result in a move towards system-to-system communication. The selection and design of new metering installations is planned to replace existing hard-wire circuits to connected parties with electronic communications.

ACTION

Investigations are underway to examine the meter replacement type, to determine when the replacement programme should commence, to select the preferred metering supply arrangements, and to assess how the replacement should proceed, ie, full replacement or partial replacement.

The actions to address metering requirements include:

- acquiring a small number of new meters to replenish current stocks and reduce Transpower's immediate supply risks
- developing and approving a revised metering policy and design standard that can be used to evaluate the meter replacement programme.

3.5 Transmission lines

The transmission lines asset class comprises all towers, poles, foundations, conductors and accessories including spacers, dampers and insulators. This class includes both AC and DC overhead transmission lines but excludes underground cables and submarine cables.

Transpower has over 11,000 route km of transmission lines, supported by poles and towers and configured as single circuits and double circuits, as shown in Table 3-18. Double circuits have twice the length of conductors of single circuits.

Table 3-18: Transmission line length (route km)

	Single circuit (route km)		Double circuit (route km)		Total
kV	**Poles**	**Towers**	**Poles**	**Towers**	
350	3	11		556	569
220	7	2903	2	2990	5902
110	2126	554	56	1863	4598
66	213	39	167	153	572
50	137	0	0	2	139
33	20	0	0	0	20
11	5	0	0	0	5
Total	2510	3506	225	5565	11806

Notes:

350kV (HVDC) includes earthing electrode line lengths (0 kV)

Route km measures length of line irrespective of the number of circuits.

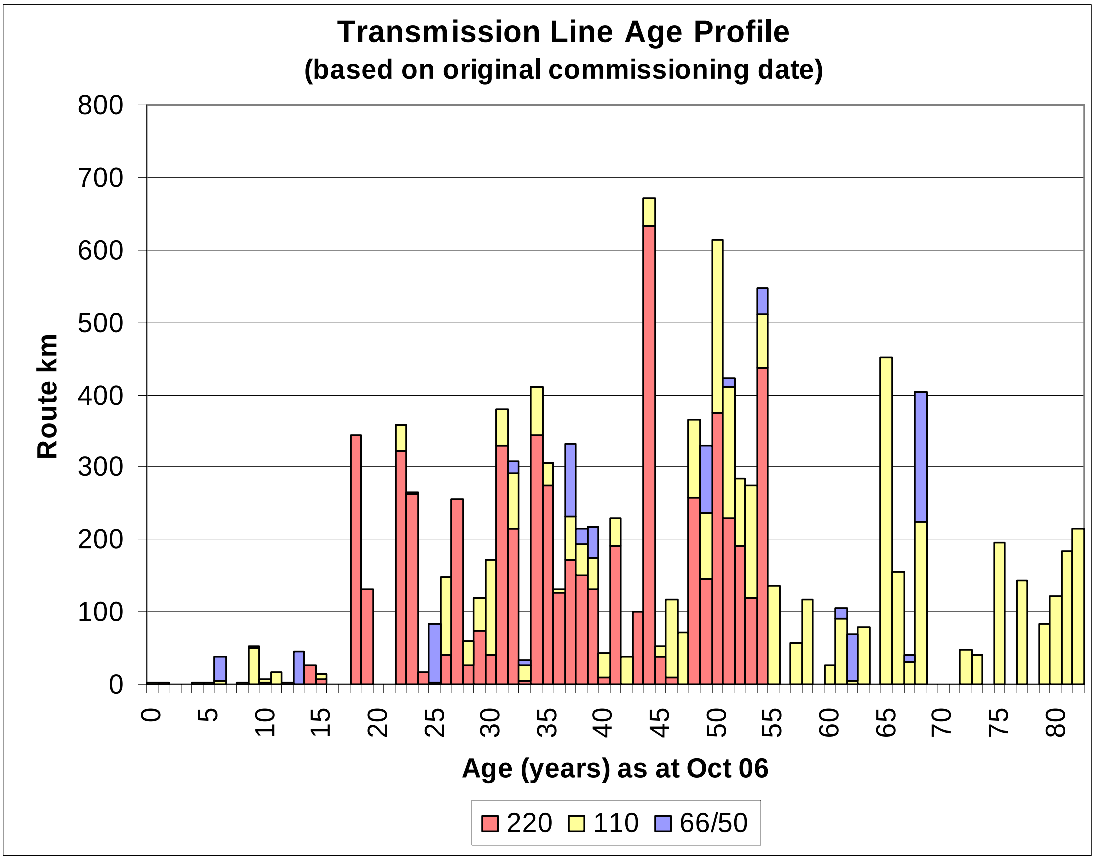
Most of Transpower's existing line routes were constructed over 40 years ago. The age profile of lines by voltage is shown in Figure 3-9.

3.5.1 Transmission line asset management

Transpower operates an extensive condition assessment programme that monitors and records the condition of transmission line structures, conductors and hardware. This programme applies a consistent approach when assessing the condition of line components and allows extrapolation of the assessed condition into the future. From this, replacement or maintenance options can be investigated. This approach allows maintenance planning to take into account the impact of varying environmental ageing factors in an effective manner.

Transmission line maintenance practices are benchmarked against those of comparable international utilities in forums such as CIGRE meetings. In general, Transpower's practices are in line with those of other utilities, and follow best industry practice. This is particularly the case with the extent and detail of the condition assessment process for transmission lines, and the use of predictive models based on condition assessment data.

Figure 3-9: Transmission line age profile



As a minimum, each tower and associated span has its condition assessed every eight years and each pole structure every six years. Assessments are performed more frequently if the structure or span falls into any of the following three categories:

- the condition of any asset component has deteriorated to a predetermined level
- the asset is located in an aggressive environment, eg, those in particularly polluted or windy environments
- the structure/span is deemed to be highly critical, eg, due to its overall position in the grid, or where failure of the structure would pose an unacceptable risk to people or property.

The current status and planned actions for towers, poles, foundations, conductors and accessories, insulators, vegetation control and HVDC lines are described in the following sections.

3.5.2 Towers and poles

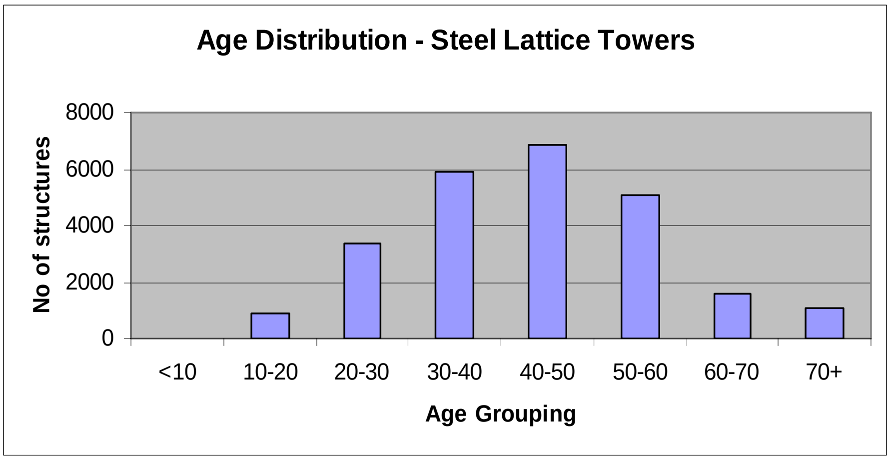
Transpower's lines utilise both lattice towers and poles. Essentially all 220kV and HVDC structures are lattice towers. Table 3-19 shows the population of towers and poles by construction type and circuit type. Multi-pole structures are classified as wood if they have at least one wood pole.

Transpower's transmission lines comprise 24,781 galvanised steel towers. Very few new towers have been constructed in recent years. Figure 3-10 shows the age profile of steel towers.

Table 3-19: Tower/pole construction type

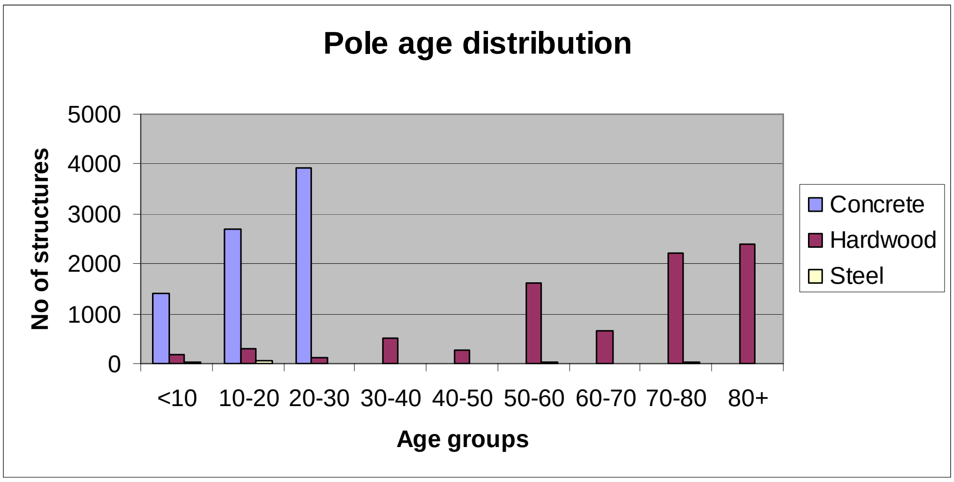
Number of structures by type		Double circuit	Single circuit	Total
Poles	Concrete	805	7407	8212
	Steel	11	159	170
	Wood	664	7368	8032
	Total	1480	14934	16414
Towers		14999	9782	24781

Figure 3-10: Steel tower age profile



Transpower began installing concrete poles in preference to hardwood poles in the early 1990s. A total of 8,032 wood pole structures remain in service, most of them original. Figure 3-11 shows the age profile for concrete, hardwood and steel poles.

Figure 3-11: Pole age distribution



Towers

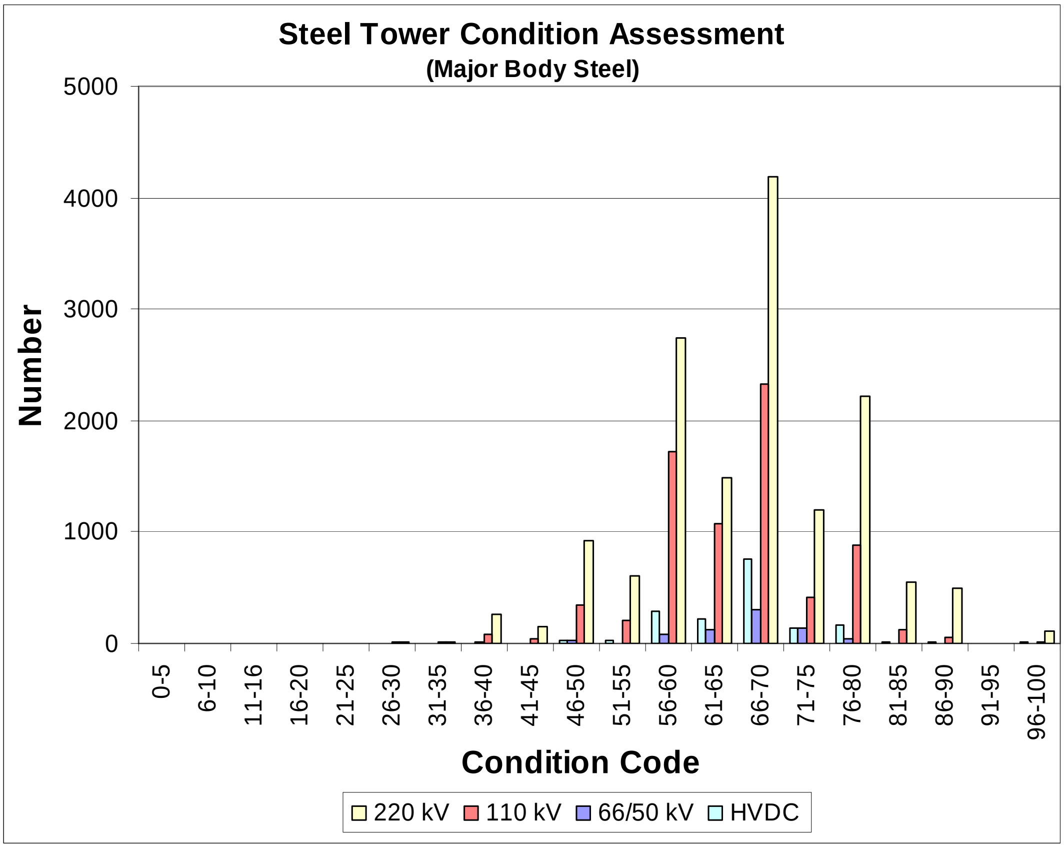
STATUS

Tower maintenance activities are concerned mainly with corrosion control. On rare occasions, members may require replacement following damage caused by third parties.

Of the 24,781 towers on Transpower's network, 44 per cent are within 25 km of the coast and a further eight per cent are in geothermal regions. New Zealand has a particularly aggressive corrosive environment, with a prevailing salt-laden westerly wind flow, geothermal regions and high rainfall – all factors affecting the rate of corrosion.

Transpower began painting towers in the early 1990s, based on assessment of zinc coating losses. To date, about 2350 towers have been painted. Figure 3-12 provides steel tower condition assessment ratings by circuit voltage category.

Figure 3-12: Steel tower condition assessment



As can be seen in Figure 3-12, a significant number of the steel towers are approaching the 50 per cent or less condition assessment rating when painting would optimally occur.

Engineering and cost/benefit studies have determined that:

- Painting increases tower life. The work can be carried out while the circuits are live, avoiding the need for costly line releases and tower replacements.
- The optimum time for painting depends on the corrosiveness of the surrounding environment

- In corrosive environments (zinc loss more than 15 g/m^2/annum) the optimum time for painting is when the Condition Assessment code for the tower is between 60 and 40. (A code of less than 40 means steel section is being lost.)
- In an environment where the zinc loss rate is below 15 g/m^2/annum, the optimum time for painting is when the Condition Assessment code for the tower is 50 or less.

Tower painting costs have risen significantly in recent years, but it is still considered the most cost-effective long-term option for the vast majority of towers. In a small number of cases, complete structure replacement, either with another tower or a pole, may prove more cost effective. However in most cases painting produces an optimum result.

ACTION

The strategy adopted for specific asset management of towers is a continued refinement of previous approaches, which requires tower painting to be emphasised in urban and highly corrosive areas and deferred in less corrosive or lower risk areas.

The number and priority of towers painted will be re-evaluated and prioritised annually after detailed asset-specific corrosion studies are completed and condition assessment data is analysed against the following tower criteria:

- towers in urban areas before extensive secondary preparation requirements
- towers previously painted with lead-based paints
- towers with proven zinc loss of greater than or equal to 15g/m^2/annum and a Condition Assessment coding of less than or equal to 60
- towers with a zinc loss of less than 15 g/m^2/annum with a Condition Assessment code of less than or equal to 50 shall be independently assessed to calculate the most cost effective long term maintenance option.

The planned expenditure on tower painting has not been confirmed beyond the current year. However it is expected to rise significantly over the next three to 10 years.

Since the early 1990s, approximately 150 towers each year have received their first coat of paint. This is expected to increase to between 200 and 400 per year over the next five years. Previously painted towers will also need recoating. This is expected to rise from 30 towers currently to 150 towers in five years' time.

Poles

STATUS

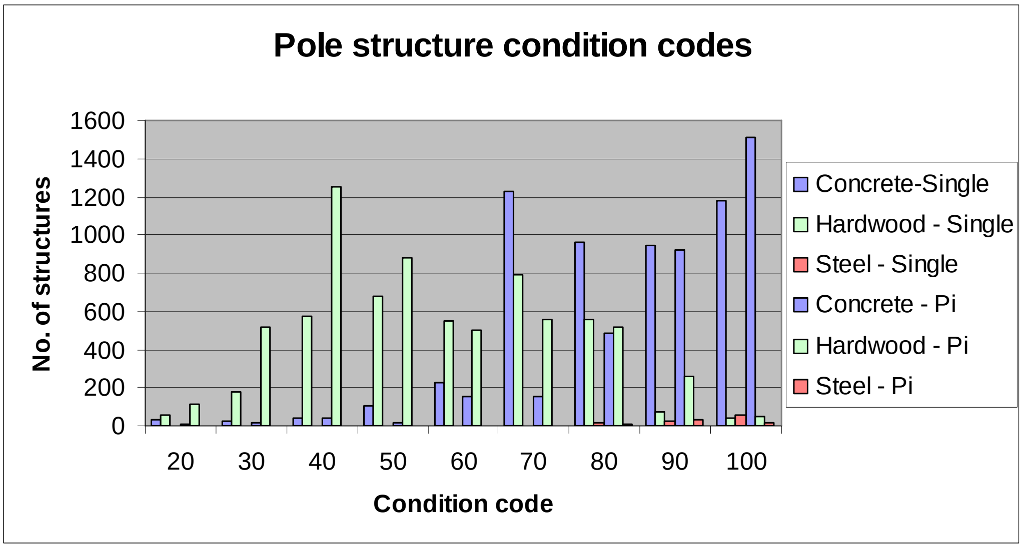
There has been a significant reduction in wooden poles since the last AMP as planned pole replacements continue following a condition assessment and replacement policy. Most of these have been replaced with concrete poles.

Figure 3-13 shows the condition codes for concrete, steel and wooden poles. A code of 100 indicates 'as new' condition, while a code of 20 indicates replacement criteria have been met.

ACTION

Approximately 350 wooden poles per annum are likely to meet replacement criteria over the next 10 years and those with low conditions codes are prioritised for replacement.

Figure 3-13: Pole structure condition assessment



3.5.3 Foundations

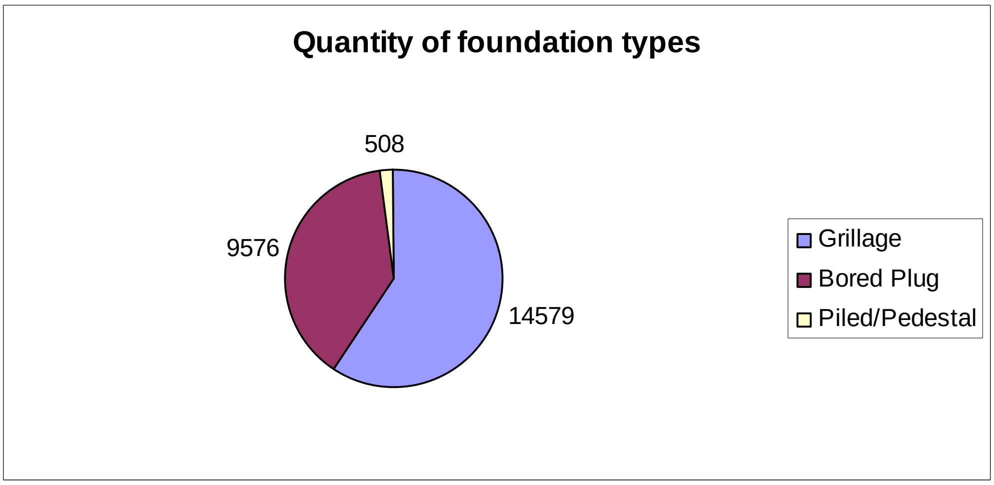
STATUS

Buried steel grillage foundations are the oldest type of tower foundation used on the grid and comprise more than half of all tower foundations – approximately 14,600 towers. Asset age ranges from 41 to 84 years.

Approximately 10,084 towers have concrete foundations. Of these, some 6,500 towers have base plate and anchor bolt base connections. This type of foundation and base connection was installed between the mid 1960s and the late 1970s. Since then, essentially all foundations have been constructed with a concrete pile/plug and cast-in stub leg. About 3,600 of these foundations exist on the network.

Piled/pedestal foundations are generally used at or near river crossings. Figure 3-14 shows the relative numbers of foundations by type.

Figure 3-14: Quantity of foundation types



Many of the approximately 14,350 towers with buried steel grillage foundations are now showing corrosion on tower legs and bracing near the ground line. Excavations have revealed that the extent of corrosion further underground, at the grillage level, varies from light to severe. Despite numerous national and international trials, no reliable non-intrusive method has been found to accurately predict which towers have corroded grillages. Age and soil type influence the grillage condition, but other factors also have an effect. The only reliable method of determining foundation condition found to date is to dig and inspect.

Base plate and anchor bolts were used on the first cast-in-situ concrete foundations Approximately 6,500 towers have this type of foundation. Poor quality dry-pack mortar originally used under the base plate on the first cast-in-situ concrete foundations (with base plate and anchor bolts) has led to mortar crumbling. Moisture ingress under the base plate has subsequently led to corrosion.

Cast-in-situ concrete foundations with cast-in stub legs are generally in good condition but an increasing number are starting to corrode at the concrete and steel interface.

Investigative testing on selected concrete pile foundations has been undertaken in the last few years using a non-intrusive testing system. This has shown that some of the tower foundations have less concrete than their design required (incorrect depth or shape), generally because of the construction methods and quality control practices at the time. Studies have also revealed that concrete foundations built before 1983 were usually designed based on very limited soil testing and often assumed soil properties, leading to undersize foundations being designed. Recent studies, including full-scale foundation testing, suggest that under-strength foundations still exist in some cases.

ACTION

Due to the age profile for grillage foundations, it is recognised that many will be approaching end of life. Transpower has recently increased the number to be inspected from two per cent to five per cent of all towers Condition Assessed each year. Data collected will be used to enhance the existing grillage refurbishment programme and ensure the structural integrity of towers with at-risk grillage foundations is restored. These foundations are refurbished by removing the corroded grillage and replacing it with a newly galvanised one. If there is no significant loss of steel section, the corroded grillage is then cleaned and regalvanised for use on another tower.

The current baseplate and anchor bolt refurbishment programme will continue. This involves removing and replacing the mortar with non-shrink grout, treating or replacing corroded anchor bolts and sealing with a paint system.

Structures with concrete pile foundations built before 1983 will continue to be investigated. Foundations found to be under-strength will be programmed for strengthening. Structures will be prioritised for investigation based on potential risk to people, property and the grid.

3.5.4 Conductors and accessories

Conductors

STATUS

Most of Transpower's existing lines were built over 45 years ago using both copper and Aluminium Conductor Steel Reinforced (ACSR) conductors. Approximately 98 per cent of the copper conducts Transpower has on its 110, 66 and 50 kV circuits are over 50 years old. Figure 3-15 shows the conductor population for aluminium and copper conductors by voltage. Figure 3-16 shows the age profile for conductors by type.

Figure 3-15: Conductor type by voltage

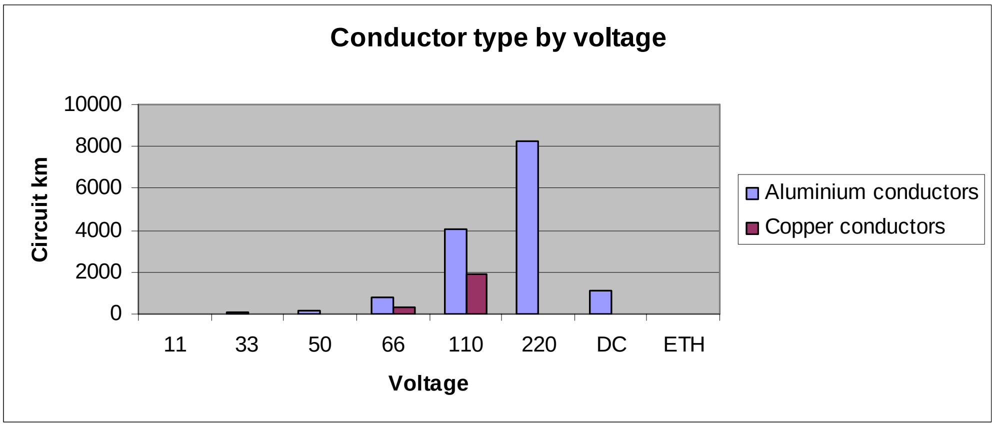
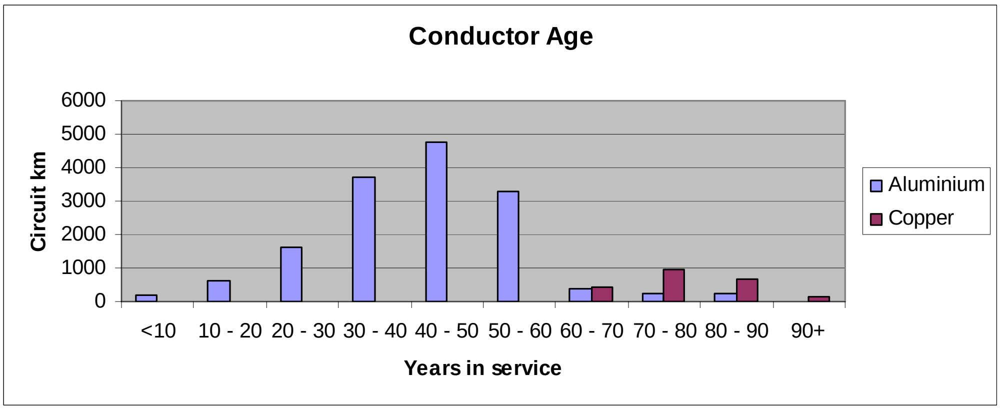


Figure 3-16: Conductor age profile



Three types of ACSR are in service. The first two types installed (ACSR/GZ) have greased and ungreased galvanised steel core wire, while the third and most recent type (ACSR/AC) has greased aluminium-clad steel core wire. ACSR/AC is more corrosion resistant than ACSR/GZ and has slightly lower electrical power losses due to its increased conductivity.

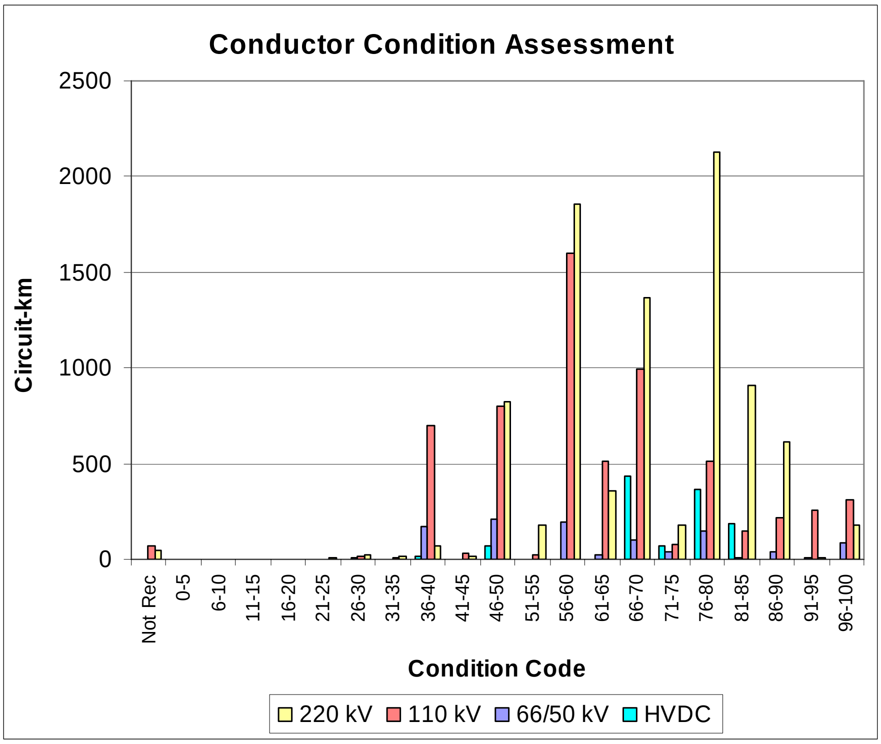
In relatively benign environments, conductors can be expected to last for 80 years. In more aggressive environments, end of life can be reached in 20 to 25 years. In some areas, environmental conditions faced by Transpower's conductors are more severe than normal because of the exposure to salt-laden wind flow and high winds.

Figure 3-17 shows the condition assessment of conductors by circuit kilometre.

Transpower has over 60,000 mid-span Aluminium Conductor Steel Reinforced (ACSR) and copper joints in service. As the joints age, the internal resistance increases. If left unchecked, this could lead to joint burning and failure.

Reconductoring projects are required as older conductors reach their replacement criteria, however replacement requirements cannot be planned for longer term forecasts until updated condition information is obtained and assessments can be completed. The forecast expenditure in this area is therefore subject to change as condition information becomes available and is fully assessed.

Figure 3-17: Conductor condition assessment by circuit-km



ACTION

Several lines are expected to require reconductoring over the next 10 years to replace corroded conductors. Enhanced condition-based information may drive additional re-conductoring or defer or bring forward the timing of planned work.

When reconductoring is required (based on the conductor condition) consideration is also given to any future enhancement requirements and, as a result, a conductor replacement is programmed as a line enhancement, even though the primary driver is the replacement requirement.

Reconductoring projects will be implemented as the older conductors reach their replacement criteria.

Table 3-20 shows a total of 961 km of planned reconductor replacements over the next five years.

Table 3-20: Conductor five-year planned replacements

	ACSR	Copper
Maintenance-driven	90 km	250 km
Network-driven	415 km	206 km

Conductor condition assessment is planned to be enhanced by a programme of close-up inspections by helicopter and the use of a non-destructive Cormon testing robot. The planned replacement programme by site listed below however the sequence and replacement requirements are subject to review and change depending on condition assessments and grid requirements.

Circuit	Forecast Date

HAY-TKR-A	2006-2008
ARI-EDG-A	2008-2017
MGM-MST-A	2008-2010
MGM-WDV-A	2008-2010
MHO-PKK-A	2008-2010
TKR-WIL-A	2008-2010
BPE-WGN-B	2009-2011
MHO-PKK-B	2009-2011
NPL-SFD-A	2009-2012
WGN-SFD-A	2009-2011
ALB-HEN-A	2010-2017
HAM-MER-B	2010-2012
AHA-OTI-A	2011-2013
ARI-HAM-A	2011-2013
ARI-HAM-B	2011-2013
CST-NPL-A	2011-2013
GNY-WTK-A	2011-2017
HAM-MER-A	2011-2013
BKD-HOR-A	2013-2015
MER-TAK-A	2013-2015

These programmes will be carried out in addition to the ground- and tower-based visual inspections and conductor sampling. Recent experience has shown that ground- and tower-based assessments alone are not sufficiently accurate to predict conductor condition.

To date, only ACSR conductors have been used to replace aged conductors. Transpower is creating specifications and drawings for All Aluminium Alloy Conductor (AAAC) to allow its use where appropriate, both for replacement and new build projects. The use of other modern conductors, such as Aluminium Core Steel Supported (ACSS), GAP and Invar Core may be considered for specific projects.

Methods to assess conductor joint condition have been evaluated and tested by transmission utilities worldwide, and technology now exists to measure the joint resistances live. Although the costs are falling, it is still considered too high for general use on the lines network and remains limited to thermal upgrading projects and investigations where there is reason to believe joint defects may exist.

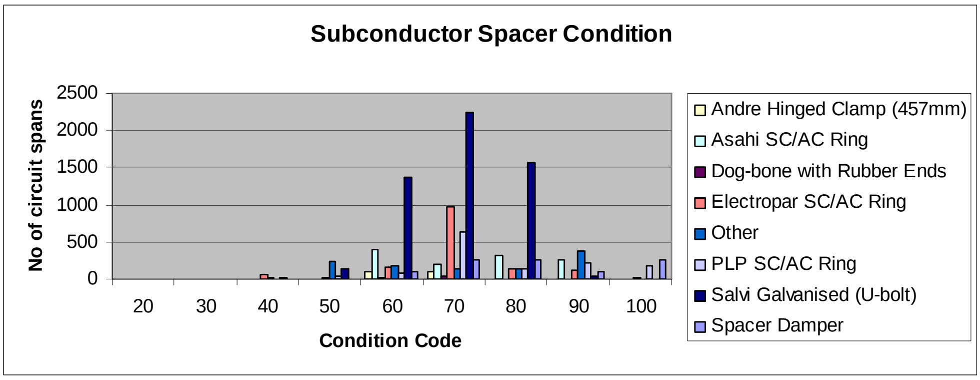
Additional works are likely to be programmed in future years as assessment information is gained.

Sub-conductor spacers

STATUS

Around 50 per cent of the 170,000 sub-conductor spacers in service are constructed with a galvanised ring that is susceptible to corrosion rates similar to those of tower steel. The remainder of the sub-conductor spacers are of solid aluminium or aluminium-clad steel. Figure 3-18 shows the condition code profile for sub-conductor spacers.

Figure 3-18: Sub conductor condition



Inter-phase spacers used to separate phases and constrain conductor movement are installed on specific transmission line spans with a history of snow unloading or ‘galloping’, which are linked to seasonal system disturbances.

ACTION

Spacer corrosion is monitored visually through condition assessment and spacers are replaced upon reaching replacement criteria. Around 200 replacements are expected each year, with some variation from year to year.

Dampers

STATUS

Approximately 80,000 vibration dampers are in service. These are constructed with galvanised messenger wires that have corrosion rates similar to those of tower steel. All dampers were installed between the early 1990s and 2005.

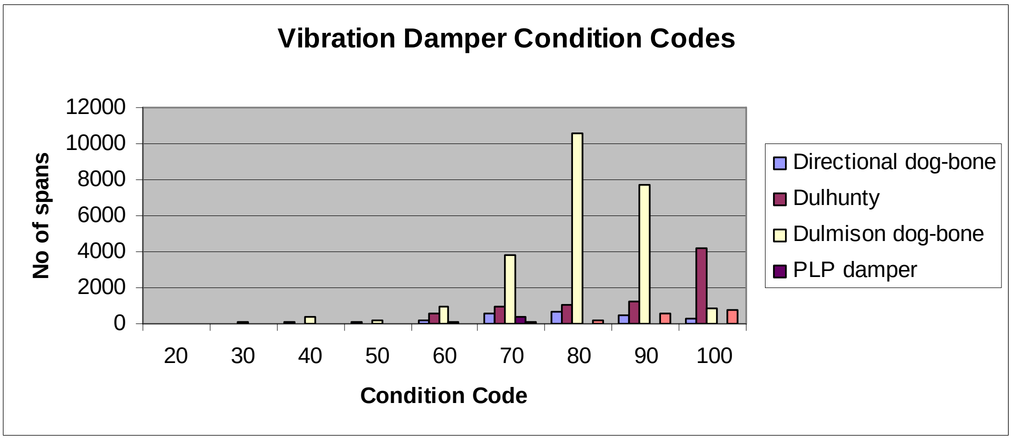
As the dampers absorb the energy from the vibration, they are essentially sacrificial and do intentionally wear out. Worn or corroded messenger wires will eventually fail to provide adequate vibration protection, and should then be replaced.

Aeolian vibration generally occurs with light winds blowing across the conductors at near right angles, causing fretting and fatigue damage to conductors – typically at the suspension points. This significantly shortens the life of the conductor. Most Transpower lines did not have vibration dampers fitted when first constructed, as Aeolian vibration was not a recognised phenomenon until around 1990. By the time this issue was identified, the conductors had already been damaged by vibration. The damper installation programme began in the early 1990s and was completed in 2005. Correctly installed vibration dampers remove the vibration before the suspension point. Figure 3-19 shows the condition code profile for dampers.

ACTION

Dampers are monitored visually through condition assessment and are replaced upon reaching replacement criteria. To date, isolated replacements have been carried out but no total line replacements have been required. An end-of-life evaluation project is under way to establish when the dampers cease to provide adequate vibration protection. This will further refine damper replacement criteria. Maintenance-driven work to replace vibration dampers is forecast to remain low over the next five years. Maintenance-driven replacements will likely be required beyond year five. This work will be programmed after the current end-of-life investigation.

Figure 3-19: Vibration damper condition



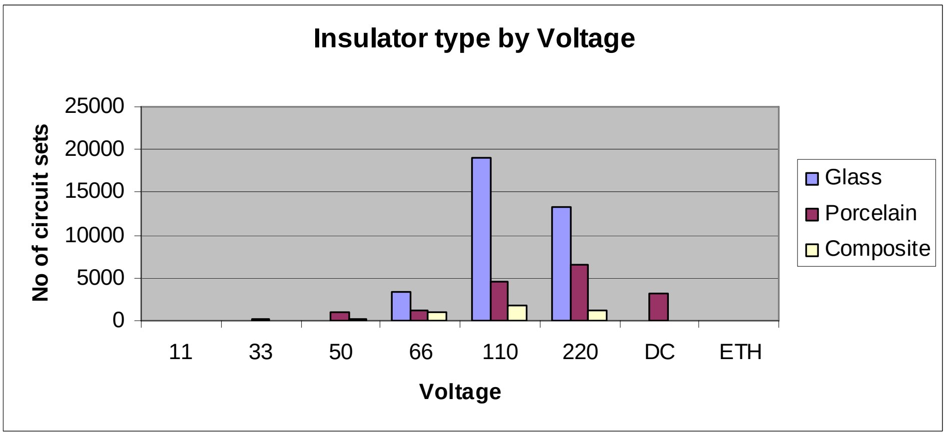
3.5.5 Insulators

STATUS

Approximately 190,000 insulator strings are in service. The three types are glass disks, porcelain disks and composite (fibreglass rod with silicon rubber sheath and sheds).

Figure 3-20 shows the population of insulator circuit sets on the network by type and by voltage. A circuit set will generally comprise three insulator strings on a suspension structure, and nine strings on a strain structure.

Figure 3-20: Number of insulator circuit sets

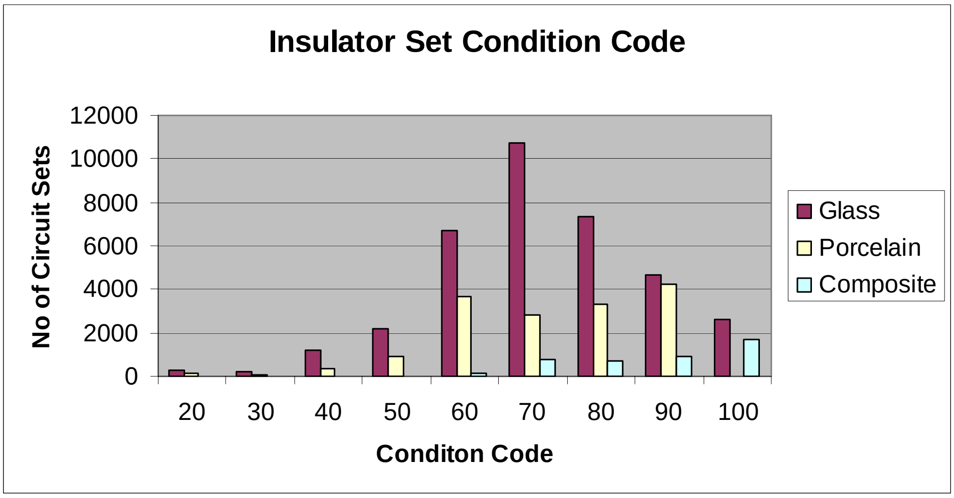


Porcelain insulators manufactured before 1970 are considered suspect due to poor quality control during manufacturing, which may lead to in-service internal deterioration of the porcelain. Figure 3-21 shows the condition codes for the various insulator sets on the network. A circuit set will generally consist of three insulator strings on a suspension structure, and nine strings on a strain structure.

ACTION

A mandatory replacement strategy of pre-1970 porcelain strings has reduced the number of such strings to approximately 1,200 today compared to about 8,000 five years ago. Insulators with low condition codes are prioritised for replacement.

Figure 3-21: Insulator condition



All replacement insulation is now with either composite (fibreglass and silicon rubber) or conventional glass cap-and-pin insulators. Composite insulators are being used in areas with medium to high contamination to increase contamination performance or to reduce insulator corona noise. Conventional glass cap-and-pin insulators may be used in areas with low contamination.

3.5.6 Vegetation control

STATUS

Vegetation control continues to be a high-cost activity. In part, this is due to the lack of any formal property rights over most of the land the transmission lines cross. Recent aerial line surveys have provided vegetation control information, which guides maintenance vegetation control work.

ACTION

Transpower's approved standard for managing trees near transmission lines is based on accepted vegetation control practices that are consistent with industry good practice and meet the requirements of the Electricity (Hazards from Trees) Regulations 2003.

When accessing property to undertake vegetation control, Transpower follows an established protocol for access agreements and codes of practice for entry onto land. If access by agreement is declined or proves difficult, then formal notice under the Electricity (Hazards from Trees) Regulations 2003 is served. When access to property is denied, the process under the regulations provides for the liability to undertake necessary vegetation control to pass to the landowner.

Section 4.2 describes the scope of vegetation control as part of routine maintenance work.

3.6 HVDC

The high-voltage direct current (HVDC) link connects the North Island and South Island power systems. At Benmore, in the South Island's Waitaki Valley, a converter station connected to the South Island grid converts power from alternating current (AC) to direct current (DC). A 535 km HVDC transmission line runs from Benmore to Fighting Bay at the top of the South Island, with 40 km of submarine cable under Cook Strait to Oteranga Bay in the North Island, and 37 km of transmission line to

Haywards. At Haywards, another converter station connects the HVDC to the North Island power system.

The HVDC asset class comprises the HVDC substations including the Pole 1 and Pole 2 converter equipment, HVDC control and protection systems, transmission lines and towers, submarine cables, cable stations, and electrode stations.

As at 1 July 2007, the two poles on the HVDC link operated at 270 kV (Pole 1) and 350 kV (Pole 2).

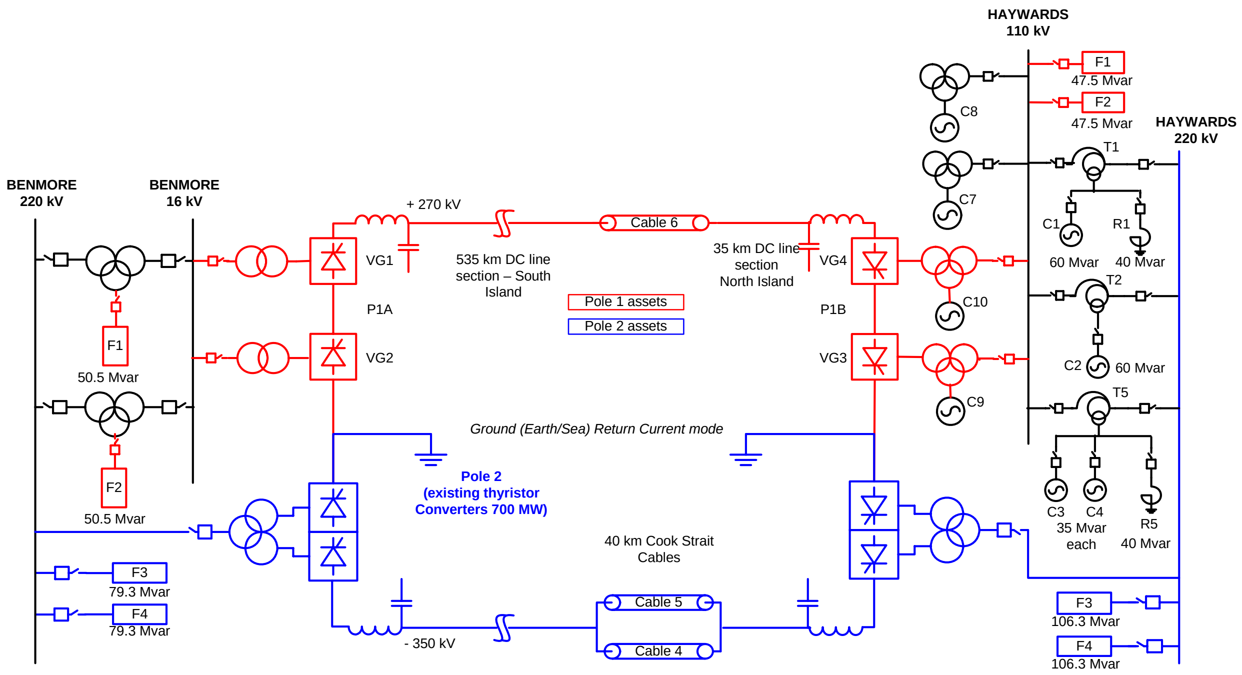
Pole	Commissioned	Converter Type	Converter Rating	Pole Capacity
Pole 1	1965	Mercury Arc Valves	648 MW	540 MW
Pole 2	1991	Thyristor Valves	700 MW	500 MW

However, in September 2007, the Transpower Board decided to “stand-down” the Pole 1 converter stations pending a review of the risks associated with continued operation of this plant. Following extensive investigations, the Board announced in December 2007 that half of the HVDC Pole 1 Converter station capacity would be decommissioned and dismantled, and that the remaining Pole 1 equipment would only be made available under very restricted operating conditions, and only during a Grid Emergency.

Until such time as the HVDC Pole 1 converter stations are replaced, only the Pole 2 converter stations will be available for normal commercial operation.

Submarine power cables 4 and 5 are now connected to Pole 2 and cable 6 is connected to Pole 1. This allows the Pole 2 converter stations to operate up to 700 MW capacity. This monopolar mode of operation requires continuous ground return current through the ground electrodes at each converter station. The present operating configuration is illustrated as follows:

Figure 3-22: HVDC configuration



3.6.1 Pole 2 converter stations

Transpower's Pole 2 thyristor converter stations were commissioned in 1991-92 during the DC Hybrid Link Project, and have a planned economic life of 30 years. The installed capacity of the Pole 2 plant is 700 MW but is constrained to 500 MW because of the allocation of two submarine cables to Pole 1.

STATUS

The Pole 2 equipment is generally in good condition. The main circuit equipment is expected to achieve its planned economic life, but needs increasing maintenance.

Condition assessment has identified increased corrosion and accumulation of aluminium hydroxide in the stainless steel couplings in the Pole 2 water cooling system. These couplings are critically important components that distribute cooling water to the thyristor valve layers. Corrosion in similar components in other HVDC thyristor valves is a possible cause of cooling water leakage, flashover and catastrophic failure of the complete thyristor valve.

Electricity market operations cause frequent changes of HVDC power transfer, tap changes of the converter transformers, and switching of the Pole 2 filter bank circuit breakers – leading to a number of circuit breakers reaching the limits of their mechanical endurance. The circuit breakers with the highest switching frequency, HAY CB762B and BEN CB752B, were replaced in 2005.

Circuit breakers HAY CB762A and HAY CB722A were refurbished with new heads and pull rods in 2007. BEN CB692B was fitted with a new type of operating mechanism.

The control equipment for the Pole 2 converter stations is not expected to have the same useful life as the main circuit equipment. Most of the control equipment is based on 17-year-old single-board computer technology and is obsolete. A substantial quantity of spare control equipment is held, but the microprocessor-based parts of the control system are likely to need replacing around 2012 to manage the risks of technological obsolescence.

The future reliability of the control and protection systems now faces additional risks (see Section 3.6.2 below).

ACTION

All stainless steel couplings in the thyristor valve cooling circuits at both Haywards and Benmore will need to be replaced between 2008 and 2010. Scheduled outages for this will be extensive – up to seven days per year.

Due to the high number of transformer tap changer operations, the Pole 2 converter transformer diverter switches will soon need an extensive and time-consuming overhaul. The outages required will be scheduled at the same time as outages needed to replace cooling system couplings.

Refurbishment of filter bank circuit breakers HAY CB 722B and BEN CB692B is planned for 2007-08.

3.6.2 HVDC control and protection systems

A number of HVDC system incidents in recent years have focused attention on the risks of deteriorating system performance caused by HVDC control and protection system faults. The control system equipment on Pole 1 was completely replaced during the installation of the Pole 2 converters in 1991-92, so the following issues are common to Pole 1 and Pole 2.

The HVDC control and protection systems are a mixture of 190 different types and families of digital and analogue electronic circuit boards. Some circuit boards are used widely as part of the ABB Master system in industrial control applications, while many others were custom-built by ABB for HVDC control applications. The complete system was state-of-the-art in the late 1980's. Around 4,570 boards are in service. The technology has been obsolete for more than 15 years, and replacement modules are becoming increasingly difficult and costly to procure.

A number of risks are associated with operating the HVDC link with an obsolete control and protection system:

- increased forced outage rate because of age-related failures of control and protection equipment, with possible implications for under-frequency event charges
- decreased HVDC system availability because of shortages of spares to replace faulty control and protection equipment
- operational difficulties because of inability to expand the functions of the existing system.

Over the years the equipment has had numerous faults, with some causing significant system disturbances.

Defects in analogue buffer cards caused trips of Pole 2 during 2004 and forced a temporary reduction in bipole transfer capacity. A programme of extensive refurbishment of analogue buffer cards was completed in 2005-06. There are limited spares in the existing inventory and increasing risks of future unavailability of a few critical items. The risk exposure varies significantly between modules, in terms of their historic rate of failure, the stock of existing spares and the present market availability of replacement spare modules.

Faulty boards will be repaired where practical, and some additional control and protection boards will be procured to improve the level of confidence in operational performance of Pole 1 and Pole 2 over the next five years. Beyond that point, the control, protection and SCADA systems of Pole 1 and Pole 2 will need to be entirely replaced.

3.6.3 HVDC transmission line

The HVDC line was built in the early 1960s. The supporting towers have since gone through three major strengthening programmes: the first was started before the line was commissioned and the last was completed in the early 1990s. In general, Transpower manages and maintains the HVDC transmission line to the same standards as its core grid AC transmission lines.

HVDC towers

STATUS

From a total tower population of 1,649, 1,504 towers on the HVDC line are still identified as being part of the original supply contract. There have been four tower collapse incidents – in 1963, 1975, 1988 and 2004 – involving a total of 14 towers.

It is now understood that a major contributor to the 14 tower failures experienced since 1963 is the effect of the Southern Alps on the prevailing westerly wind direction (ie, the orthographic lee effect). This effect was not taken into account during the original design and the strengthening works that preceded the failure.

From investigations completed to date, it is believed that a single tower failure on this line currently has a return period of approx 10 years. This is consistent with historical performance.

For much of the line length, the route is inland, generally sheltered by the Southern Alps and not exposed to the corrosive coastal conditions. Towards the top of the South Island, and for all of the North Island section, the line is considered to be in a coastal environment and has additional insulation to accommodate higher levels of contamination.

Most towers in the North Island section of the line have been replaced. These had corroded significantly and were assessed as under required strength.

HVDC tower foundations

Most towers have buried steel grillage foundations that have performed well for the last 40 years. It is unlikely these foundations will last a further 20 years without a refurbishment program or some remedial work on some of the more corroded foundations. During the most recent tower failure, the foundations performed satisfactorily and failed only after the towers had collapsed. However, in some soils the grillages could require strengthening to achieve a satisfactory performance.

ACTION

The reliability of the existing towers and foundations will be investigated and necessary corrective action plans implemented.

Conductors and insulation

STATUS

The line insulation was completely replaced during the DC link upgrade project from 1989 to 1991 when the rated voltage was increased from 250 kV to 350 kV.

The line conductors are original, but the condition of the conductor in coastal regions is deteriorating significantly.

ACTION

Re-conductoring of the coastal sections is likely to be required in the next 10 years as replacement criteria are reached. Some porcelain insulator strings in coastal regions have been replaced with composites to improve performance.

3.6.4 Submarine cables

The Cook Strait HVDC submarine cables (cables 4, 5 and 6; 350 kV 1,430 A power cables) and the first two fibre optic cables (cables 7 and 8) were laid in 1991. The three power cables are required if the present level of HVDC transfer capacity is to be maintained as there is no redundancy or spare capacity. Damage to, or premature failure of, any one of the power cables can result in a reduction of HVDC capacity to 886 MW. Two replacement fibre-optic cables (cables 9 and 10) were installed in late 2002 and are now the primary in-service fibre optic cables. The two fibre optic cables operate in parallel, so there is 100 per cent redundancy. Cables 7 and 8 remain operable but are now kept as standby cables in case of damage to cables 9 and 10.

STATUS

A remote-operated vehicle (ROV) survey in 1993 showed that the three power cables were in good condition and generally well supported by the seabed. Observations suggest that the cables are likely to have a useful life of at least 30 to 40 years in respect of severe abrasive damage to the serving. However, the 250/270 kV cables 1, 2 and 3 laid in 1964 (now out of service) were found in 1993 to have suffered significant armour damage (total loss in some sections) in parts of the high tidal current area known as the Terawhiti Rip, two to 10 km offshore from Oteranga Bay. Work during the 1996 ROV-2 project established that this was caused by the aggressive abrasive environment resulting from gravel and sand being transported on the seabed and over the cables by the tides. The polypropylene serving on cables 4, 5 and 6 so far seems more resistant to abrasion than the jute serving on cables 1, 2 and 3, but the extent of their abrasion damage warrants ongoing monitoring.

The 1993 and 1996 ROV surveys also found conclusive evidence of damage to fibre optic cable 7, caused by illegal fishing activity.

The Submarine Cables and Pipelines Protection Act 1996 provides legal protection of a Cable Protection Zone (CPZ) across Cook Strait, and is intended to prevent the risk of damage to the cables from fishing activities. However, frequent violations of this CPZ have resulted in cable damage. In 1995 Transpower started marine patrols of the Cook Strait CPZ, initially focusing on the hoki fishing season from June to September (the time of greatest risk of damage from illegal fishing). Cable breakage incidents (see below) and efforts by fishermen to circumvent the (then) part-time patrol led to full-time patrolling, which has been in place for some years. An ongoing, highly visible presence is maintained to deter illegal fishing.

In 1998, fibre optic cable 8 was fouled and broken by trawling. The cable has been repaired but now does not follow its as-laid route. In July 2000, fibre optic cable 7 was fouled and broken by fishing vessel trawling gear and repaired in August 2000. Surveys have also found that cable 7 had been dragged north, resulting in two crossovers between cables 7 and 4. Cable 7 has been pulled tight and now contains a number of additional suspensions.

In October 2004, 350 kV cable 6 failed in very shallow water (about 5 m deep) about 200 m offshore in Oteranga Bay, with the cause not completely established (but not illegal fishing or anchoring). Repair was completed in March 2005, supported from a shallow-draft barge.

Transpower, Telecom, Southern Cross Cables and Shell Todd Oil Services have applied to the Minister of Transport to have improvements made to the Submarine Cables and Pipelines Protection Act 1996, to help gather evidence of vessel and fishing activities and improve the chances of a successful outcome to an investigation. The first application was made in 2000 and an updated application has since been drafted. The Ministry of Transport has advised that any new application is now not likely to reach the government’s legislative programme before 2009 at the earliest and more likely 2010.

Due to the nature of the marine environment, corrosion of areas of exposed armouring on the cables was expected, with cathodic protection needed on the cables. However, ROV surveys and diving have shown virtually no corrosion of the armouring to date. The recently completed (November 2006 – January 2007) ROV and diving survey in Oteranga Bay has again found exposed armouring to be in sound order. A cathodic protection process seems to be occurring naturally, possibly due to a natural voltage difference between the North Island and South Island.

ACTION

It was determined at the 1993 ROV survey that an ongoing programme of inspection was needed to regularly monitor cable condition and help understand the deterioration processes caused by the marine environment.

Full ROV inspections of selected parts of the cable corridor were planned for about every three years until a history was established and trends observed. After the 1996 survey, this interval was extended to five years. The cost of ROVs and dynamically positioned support vessels is driven by world demand from the offshore oil and gas industry, is volatile and worldwide demand is currently high. However, in October 2000 Transpower, with Shell Todd Oil Services, formed an agreement with a local ROV survey provider, giving access to a New Zealand-based ROV at a stable, much lower price than overseas sources, allowing a return to the preferred three-yearly inspection. This service was used for surveys in 2001, 2004 and late 2006/early 2007. The next ROV inspection is planned for the 2010 summer.

Diving inspections of the cables in near-shore seabed areas have checked the condition of cables in the severe environment of Oteranga Bay. Earlier survey results showed that the previously planned three-yearly dive inspection could be amended. It is proposed that ‘deep’ inspections (25 to 45 m) be made every five years and ‘shallow’ inspections (up to 25 m) continue at three-yearly intervals. The overall effect is to reduce the average annual cost of dive inspections. The last inspection was in the 2007 summer. The next inspection is planned for the 2010 summer.

A diving inspection of the cables in the near-shore seabed areas of Fighting Bay in the 1999-2000 summer found that all cables were self-buried within Fighting Bay. Given the degree of protection likely, it is assumed that the cables are in sound condition. No further routine inspection of these cables in Fighting Bay is expected to be required in the medium term. No further natural cathodic protection investigations or any further prevention action is planned to be taken at this stage.

The Transpower-initiated marine patrol service of the Cook Strait CPZ, started on a seasonal basis in 1995, has for some years been extended to year-round patrols. Prosecutions by the Ministry of Transport for illegal fishing continue, based on evidence from the patrol vessel.

The shallow draft barge used for the 2005 cable 6 repairs will remain in New Zealand waters to meet future repair requirements.

3.6.5 Cable stations

STATUS

The submarine cable stations at Fighting Bay and Oteranga Bay were modified and upgraded during the DC Hybrid Link project in 1991. Both stations are affected by the severe maritime climate of Cook Strait and need regular attention to monitor corrosion and deterioration of buildings and structures. However, except for the roof bushings, the cable terminal buildings and equipment can generally be expected to last at least another 20 years.

The HVDC cable station at Oteranga Bay faces extremely severe environmental conditions, with regular gale and storm force winds from both north and south. In storm conditions, heavy salt deposition occurs. This is possibly the most demanding operational HVDC site world-wide in terms of environmental conditions, which cannot be directly simulated by any HVDC electrical equipment type tests. The high wind speed and constant windborne salt pollution significantly reduce the life of the outdoor roof bushings. The extreme conditions place very high stresses on porcelain type bushings.

To help gain some experience with newer technology at this site, a 270 kV-rated SF_6 gas-filled composite bushing with silicon rubber sheds was installed in the Pole 1 roof bushing position at Oteranga Bay when the upgraded HVDC link was commissioned in 1991.

The Oteranga Bay Pole 2, 350 kV porcelain roof bushing failed in service during 1996 after four years of duty. It was replaced with a spare porcelain bushing, and in February 2000, there was a further replacement with an SF_6 gas-filled composite bushing with silicon rubber sheds.

While some difficulties have also been experienced with the composite bushing, this is still the preferred technology because of the superior external insulation performance.

A new composite 350 kV roof bushing of improved design was procured in January 2005, and installed in the Pole 2 position at Oteranga Bay in February 2006.

The original Pole 1 270 kV composite roof bushing has been in service at Oteranga Bay since 1992. It is also showing signs of deterioration and will probably require replacing in three to five years.

The Fighting Bay Cable Terminal station has a much less severe climate than the Oteranga Bay site, and this leads to reduces stresses on the insulation of the roof bushings. However, diagnostic tests of the two porcelain roof bushings at the Fighting

Bay station have revealed some signs of deterioration in the bushing in service on Pole 2.

The Oteranga Bay main control block building roof and cladding were replaced in February 2006.

ACTION

Routine maintenance of the cable terminal stations is typically planned around annual shutdowns. Regular condition assessment is undertaken of Pole 1 and Pole 2 roof bushings, including visual inspection, monitoring of corrosion in the sealing and central flange area, hydrophobicity test, monitoring of internal bushing gas pressure and top-up intervals, and bushing gas analysis. Roof bushings are regularly cleaned to maintain hydrophobicity at a required level.

A replacement will be procured for the Fighting Bay Pole 2 roof bushing together with an additional unit to serve as a spare for either site.

The Oteranga Bay 350 kV cable terminal building is likely to need re-cladding in about 2010.

3.6.6 Electrode stations

STATUS

Both electrode stations were substantially upgraded during the DC Hybrid Link project. The service life of electrodes depends on the quantity of electrode current passed through them over time. The normal operating mode of the HVDC link is in balanced current operation where the electrode current is very small. As long as unbalanced current operation makes up only a small proportion of total operating time, then relatively little maintenance of the electrodes should be required over the next 20 years to deliver adequate performance.

However, electrode inspection at Te Hikowhenua in December 2005 showed that the electrodes were completely covered with a thick layer of magnesium and calcium hydroxide, a result of operation as a cathode. This layer has increased the resistance of the electrode significantly, increasing step voltages, and marine voltage gradients in the vicinity.

ACTION

New electrodes have been ordered and are being installed in 2007-08.

3.7 Information technology

3.7.1 Telecommunications and networking

Transpower's communications network is a mix of different technologies with a wide range of ages and capabilities. Table 3-21 shows the expected life and average remaining life of communication assets. The age profile of the communication assets is shown Figure 3-23.

Table 3-21: Average remaining life of communication assets

Asset Profile	Depreciated life (yrs)	Avg of remaining life (yrs)
Antennas & Networking equipment	8	-

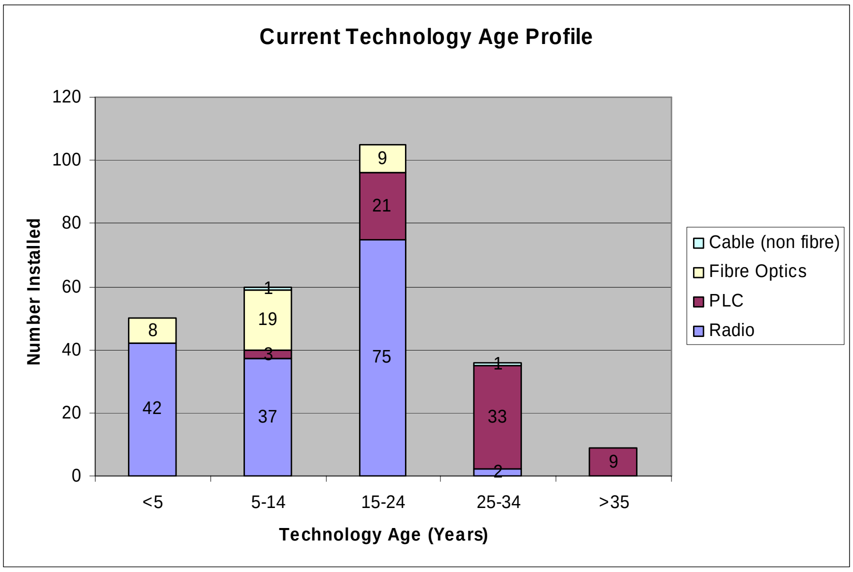
Comms electricity supply	52	46
Comms Fibre Optics	25	21
Comms: other comms equipment	10	5
Communication DC Systems	8	5
External Comms lines	25	7
Multiplexing & Interfacing Equip	10	2
Other Panels	25	9
Powerline Cable Carrier	15	0
Radio Towers & Earthing	25	7
Radios	10	1
Telephone equipment	10	1

The telecommunications network is in a transitional state and the existing assets need to be understood in the context of the future plans. The first year of a five-year telecommunications and networks strategic plan has started. This will build the core telecommunications transmission network linking major grid operations centres, upgrade corporate telephone systems, and provision security platforms and network management systems.

STATUS

The present network provides telecommunications bearers for operational and administrative voice and data, protection signalling, SCADA, real-time video conferencing and circuits leased to third parties. The network is a mix of different suppliers, technologies and equipment models with a wide range of capabilities. It is inflexible and costly to operate and maintain.

Figure 3-23: Current technology age profile



3.7.2 SCADA and RTU configuration database (SARC)

STATUS

The existing system for documenting and managing the configuration information for Transpower's RTUs associated with the national SCADA system is presently accommodated on more than 2,700 spreadsheets. This is considered to be unsatisfactory and a project is in place to address this issue.

The present system is expensive to operate and exposes Transpower to a high risk of system malfunction.

ACTION

A project to develop a database to manage RTU and SCADA configuration and cabling information is underway, with commissioning scheduled for the 2nd quarter 2008. This project will replace all existing spreadsheets used to manage RTU configuration information

3.7.3 Substation data acquisition

STATUS

The remote terminal units (RTUs) associated with the national SCADA system is a mix of different technologies with a wide range of ages and capabilities. This technology is now heading towards the end of its lifecycle.

ACTION

An investigation project is underway to start the move towards Substation Management Systems (SMS) with a first full implementation planned for a new substation at Drury in 2010 and Pakuranga upgrade in 2011. Transpower will likely be rolling out the technology from 2011 onwards across all substations as they come up for replacement work or upgrades.

3.7.4 IT&T

Transpower has a complex and diverse infrastructure platform supporting both business and critical applications. . The infrastructure platform consists of Data Centres, networks, telecommunications, servers, workstations, laptops, and peripheral devices (ie printers, scanners etc). While these technologies support Transpower business today, these systems are expensive and difficult to manage and maintain.

ACTION

Four programmes of work have been created to focus on improving services, reducing costs and simplifying the technology for ease of support and management. These programmes are

- Infrastructure and OS – the focus is to complete a strategy review on the Data Centres and replace core technologies that are no longer “fit-for-purpose”. These include but are not limited to File and Exchange projects
- Security – align the security platform that protects Transpower information and critical systems with the new security policy.
- Disaster Recovery – build on the current process, procedures and practises in place.
- Management and Monitoring – build solutions that enable business views of critical application technologies. Build on the current solutions provided via third parties and enable monitoring of new applications like MSP.

3.8 Property, easements and consents

Transpower owns property and easements for the purposes of building, owning, operating and maintaining the grid. Most of Transpower’s transmission network is protected by statutory rights set out in the Electricity Act 1992 rather than by a registered property right. At present, about 98% of the transmission network is protected by this regime with the rest protected by easements. The statutory rights allow Transpower access to maintain, operate and up-rate its assets.

Transpower is required by Regional or District Plans to gain consents under the Resource Management Act where required for some aspects of building, maintaining and operating the grid. Transpower holds 1,228 consents of various types. The types of consents held include discharge consents to air, land and water; water take rights; land use consents; subdivision consents, coastal permits and designated sites.

The majority of Transpower’s transmission lines have been established under legislation that ensures that the lines are lawfully established. This lawful establishment allows Transpower to inspect, maintain, repair and upgrade the works subject to there being no injurious affect caused to the land.

With the establishment of easements for new lines, access to existing lines has become increasingly difficult and time-consuming to negotiate. Landowner expectations of payment of compensation for existing works are causing issues. Transpower has a strategy for establishing “access agreements” on an individual basis as required. It is intended that working relationships with landowners will improve as the agreements are put in place.

4 ROUTINE MAINTENANCE AND REPAIRS

The routine maintenance plan and budget is developed to maintain assets to Transpower standards and policies. Cyclic scheduled expenses, such as periodic inspections and rates, are based on annual schedules and current prices. The budget and plan for unscheduled works (fault restoration, operating and routine repairs) are based upon historical data, but can vary in areas due to variable scope of work (eg, higher than normal fault rate).

The maintenance plan and budget are developed in conjunction with service specifications determined by Transpower standards, contractor reports and an internal challenge process. The routine maintenance activities are grouped to six categories:

- routine repairs
- inspections
- special inspections
- operating
- faults
- service charges.

Each category is broken down further into transmission line assets, station assets, revenue metering and facility management. Service charges cover costs such as land rates, third-party lease costs (eg, when co-locating on generator sites), electricity connection and use charges and water usage costs.

Contractors for Transpower provide services under period maintenance contracts. Routine maintenance is carried out through the period maintenance contracts, except for facility management, which is completed by a separate period contract. The maintenance contracts are supported by service specifications for each work activity.

A description of the asset maintenance work for each category is provided in the following sections.

4.1 Routine repairs

4.1.1 AC and HVDC stations

Repairs work is condition-based maintenance and excludes any work covered under the faults and inspections categories. Generally this work is identified during site inspections, condition monitoring, or during the ‘inspections’ category of work detailed below. It also provides for other work that may be incurred relating to maintenance. Examples of routine repairs include:

- transformer unit changes
- corrosion control
- operating mechanism issues for circuit breakers
- removing contamination on structures and buswork
- contact re-alignment of disconnectors and earth switches
- protection downloads – requested by various Transpower parties
- repair of can failures on capacitor banks
- battery bank and charger repairs
- investigation work – eg, incident reports for equipment failures

- repairs of fences, civil works and buildings (facilities management contract).

Increases in routine repairs are due to the following reasons in the various asset categories:

- transformers – no replacement of aging assets and reduced refurbishment. Additional transformers being installed in the northern North Island will enable outages for maintenance on old transformers which have previously been difficult to access.
- reactive power plant – increase in installed capacitor banks and greater focus on protection and monitoring.
- structures and buswork – increased focus on the condition of earth wires and earth peaks.

4.1.2 Transmission lines

The routine maintenance plan and budget for transmission lines covers all minor repair works on towers, poles and associated components, such as insulators and hardware, conductors and accessories and tower foundations. It also includes the control of vegetation and the maintenance of access roads and bridges.

Structures

The routine maintenance plan and budget for this category covers minor works on structures (towers and poles) and mainly caters for short-term situations where a tower or pole is either at risk, and/or presents a risk to third parties, or the structure require minor maintenance works for its integrity. Typical examples are:

- LSD CPI and OPGW sign replacement and/or repairs
- tower member maintenance
- anti-climb frames installation and repairs
- mitigation works on conductive structures and fences
- repair and reinstatement following vandalism damage
- removal of birds' nests and other foreign objects and debris
- touch-up painting and rust repair works
- responding to developers and landowners for NZECP34 advice, etc.

Conductors and conductor accessories

The routine maintenance budget for this expenditure category covers minor works on conductors and conductor accessories and caters mainly for short-term situations where a conductor is either at risk, presents a risk to third parties, or the conductor or accessories need minor maintenance for their integrity. Typical examples are:

- lightning conductor damage
- wire strikes caused by third party cranes and trucks etc
- fires under conductors and any associated conductor repairs
- joint repairs
- sub conductors, inter-phase spacers or vibration dampers working loose
- vandalism repairs
- mandatory replacement items
- vibration measurements
- conductor-to-ground measurements for buildings and line crossings etc.

Foundations

The routine maintenance plan and budget for this expenditure category covers minor works on foundations on towers and, to a lesser extent, on poles. It caters mainly for short-term situations where the ground conditions or foundations conditions have changed causing a threat or risk to the structure, or the foundations need minor maintenance for their integrity. Typical examples are:

- river diversion or bed protection works
- checking/repairing splice and anchor bolts
- tower base/ground connection maintenance and repair (including grout replacement)
- water pooling around tower bases
- earth or ground subsidence or movement
- animal congregation damage
- vehicle and farm activity damage
- minor grillage and direct buried steel and associated interface repairs
- dead-men anchor integrity tests.

Insulators and hardware

The routine maintenance plan and budget for this expenditure category covers minor works on insulators and associated hardware and caters mainly for short-term situations where the insulator and/or hardware is either at risk, and/or presents a risk to third parties or requires minor maintenance for its integrity. Typical examples are:

- replacing damaged insulators caused by weather, birds, shot, lightning, etc
- RF or physical noise complaints and remedial works to correct this
- vibration damage affecting insulators and hardware
- insulator and hardware change associated with other maintenance works
- replacing mandatory replacement items
- composite insulator washing, cleaning and hydrophobicity tests
- insulator washing and cleaning in coastal areas
- removal of foreign matter and debris.

Vegetation

The routine maintenance plan and budget for this expenditure category covers all vegetation works in the transmission line corridor and caters for all situations where the vegetation presents a risk to the safe and secure operation of the circuit. Landowner relationship management is also incorporated into this category.

Typical examples are:

- removing vegetation threatening the line conductors to comply with legislative requirements
- maintaining satisfactory clear vegetation corridor under line conductors
- identifying and, where possible, removing vegetation encroaching the growth limit zone and within fall distance
- liaising with landowners about plantations/sentimental and shelter belt vegetation, etc
- locating and managing public vegetation, ie, National Parks, reserves, etc

- easement vegetation costs associated with standard easement agreements managing vegetation in accordance with the Electricity (Hazard from Trees) Regulations 2003.

Access roads and bridges

This expenditure category covers all works on access roads and bridges and caters mainly for all situations where access to key assets is required. Maintaining access tracks and bridges guarantees access to key areas in an emergency. Regular access maintenance also helps address past landowner commitments and strengthens landowner and public relationships. Transpower also has a responsibility to maintain any access to meet acceptable safety standards. A work practice has also been established with owners and/or managers of access roads and bridges for these to be maintained to an acceptable and safe standard, particularly where members of the public also use these facilities. Typical examples are:

- maintaining 4WD access tracks on private and public lands
- maintaining and diverting culverts and water courses
- bridge assessment and minor repairs
- water table and water diversion maintenance
- maintaining access gates/fences
- controlling vegetation on access tracks
- liaising with landowners on access tracks and bridges, etc.

The plan and budget for each year is based on the average cost for each activity per asset over the last three years and adjusted for general rates increase. Another calculation allows for maintenance variation costs asset due to structure types, age, terrain and route length.

4.2 Inspections

4.2.1 AC and HVDC stations

The scope of these periodic scheduled activities and the intervals are set by Transpower policies. Inspections are carried out in accordance with Transpower service specifications. Inspections by contractors also cover certain administration service activities included in the maintenance plan and budget, such as works programming and management, fault response call-out administration, administration of records, contract works reporting, administration/control of procurement of contractor supplied and Transpower-owned spares and materials.

This category also covers site inspections, and security inspections of fences, civil works and buildings required under the facilities management contract.

4.2.2 Transmission lines

The inspection category covers line management, line patrols and condition assessment.

Line management

This category covers the fixed management component of the Alliance contracts.

It also covers contingencies for emergency tower exercises and miscellaneous work for specialist engineering and other non-contractor and consultant work. The contractors have additional processes to manage the changes associated with the tree regulations, Transpower’s commitment to landowners, Department of Conservation, and the complaint procedures and various easements and landowner agreements. Typical examples of this spend category are:

- detailed annual and monthly work programme
- monthly and special ‘as required’ reporting
- Transpower materials management (routine works and emergency preparedness)
- landowner/access and vegetation database management
- fault call-out and escalation management.
- recording and maintaining historic, landowner, vegetation and all line-related documentation
- monthly and quarterly Alliance meetings
- recruitment and training.

Routine patrols

This category covers the fixed routine patrols included in the Alliance contracts, as well as contingencies for additional patrols not included in the fault response category.

More work is involved from the introduction of the tree regulations where extra measures are necessary to identify tree-to-conductor clearances and the notification process associated with this. The New Zealand Electrical Code of Practice for Electrical Safe Distances (NZECP34) also requires significant attention for field compliance.

The routine patrol service has been changed to focus on system security and integrity items only, ie, identification of defects/situations that could disrupt the supply of electricity, damage assets and/or cause harm to someone.

Condition assessment

This category covers the fixed condition assessments included in the Alliance contracts.

Condition assessment services are based on a scale determination process to identify the condition of all transmission line structures, components, foundations and conductors. All towers are inspected on an eight-year cycle and poles on a five-year cycle. Adjustments are made to this schedule depending on condition assessment levels of specific items where these may be inspected more frequently.

The category also includes contingencies for additional assessments that may be initiated by Transpower or contractors.

4.3 Special inspections

This category covers maintenance and special inspections of stations equipment at the Otahuhu, Bay of Plenty and Islington warehouses. Requests for this work can come from the procurement group. The category also covers work associated with patrolling Transpower’s power and communication cables in Cook Strait and detailed cable inspections using a submersible remote operating vehicle and scuba diving.

4.4 Operating

The operating category is the responsibility of Asset Operations and is managed under a separate operating contract. It covers scheduled and unscheduled operating.

Scheduled operating covers the management of the Regional Operating Centres (ROC). Unscheduled work includes switching carried out by the maintenance contractors on behalf of the ROC, and is requested by parties such as the ROC and customers. Updating and managing the single line diagrams and relay and instrumentation diagrams are also part of this category.

4.5 Faults

4.5.1 AC and HVDC stations

Fault callouts are generally initiated from the ROC but can also originate with the IST call centre. If equipment must be fixed after the original callout, it is covered in the repairs category.

4.5.2 Transmission lines

This routine maintenance category covers fault response activities. Fault callouts are initiated by lightning/adverse weather, public or landowner calls, earthquake checks, transient faults etc.

Faults that are located and repaired are covered by the relevant related activity that initiated the situation, ie, insulator failure work would fall under the routine maintenance for insulators and hardware.

This category also caters for the ongoing management of the Lindsay and BICC temporary towers, associated emergency equipment and management systems.

5 FINANCIAL SUMMARY

This section provides a summary of Transpower's Financial Plan. This covers the comprehensive plan for asset management and operation of the grid and includes capital and operating expenditure for the asset management projects and activities. Forecast operating expenditure is inclusive of inflation. Forecast capital expenditure is also inflation-adjusted and includes not only the Asset Management refurbishment and replacement investment, but also customer and IST development projects and major capital development programmes that are the subject of Grid Upgrade Plans.

The financial tables and graphs in this section provide 10-year projections of estimated operating and capital expenditures to be recovered from transmission customers. These are included in the Asset Management Plan at the request of the Electricity Commission.

While the Asset Management component of the plan is stabilised by the well-understood drivers of asset refurbishment and renewal, the plan is dominated in the earlier years by capital development projects.

The first five years of the plan are determined by efficient delivery of projects to meet need-by dates following a least-cost project planning and delivery methodology. The plan may be impacted by approval delays, incurring increased project costs through the need to utilise less efficient delivery methods to meet the need date. Consequential impacts from this include lower than planned investment in the earlier years, time compression of project delivery and increased cost in later project phases, representing rescheduled activities.

Accordingly, readers can expect that; more distant capacity enhancements will continue to be added to future plans in year six and beyond as projects are developed to meet emerging grid needs; and there will be some approval related volatility in timing and cost for projects in years three to five.

5.1 Operating expenditure

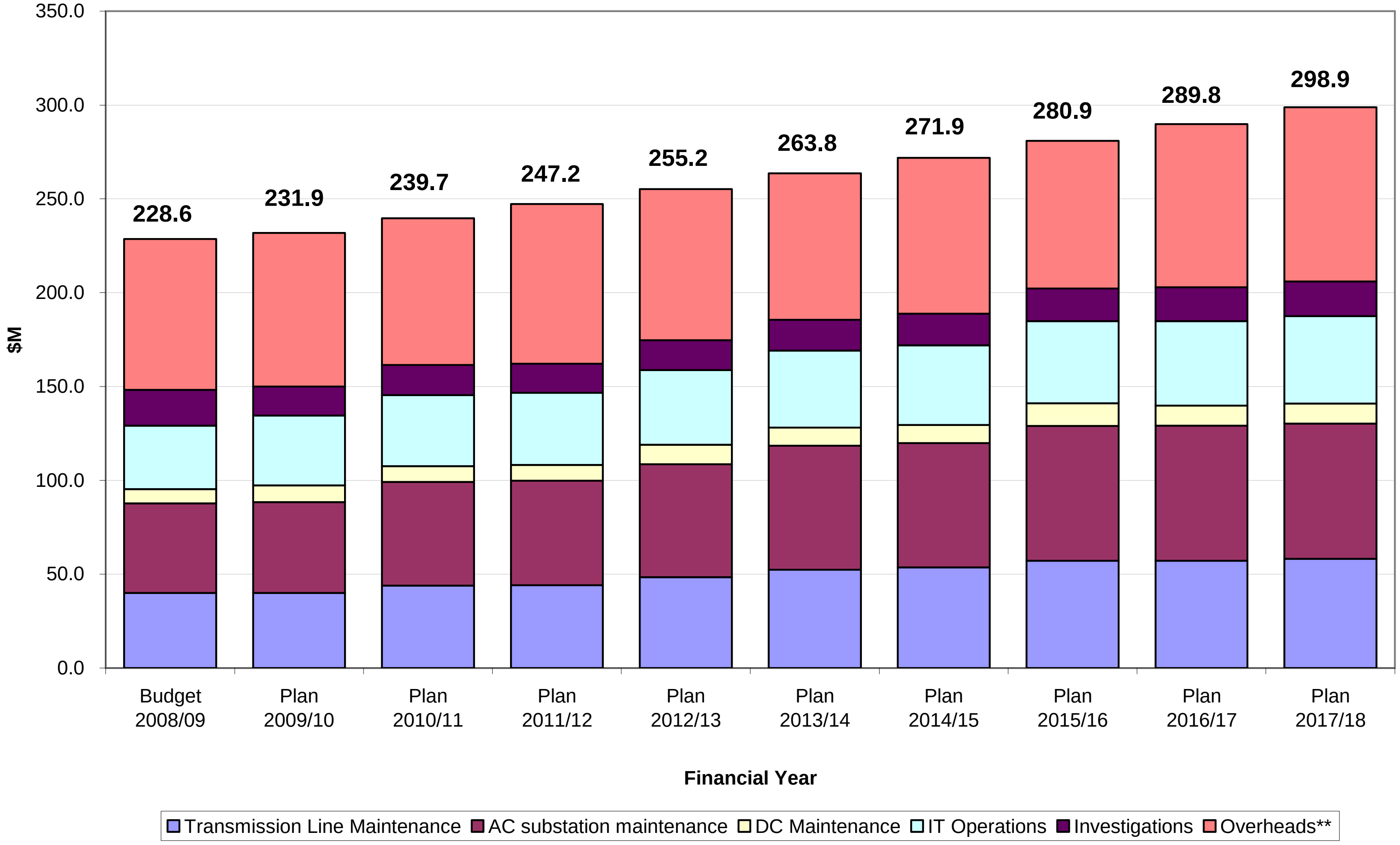
Table 5-1: Forecast operating expenditure*

	Budget 2008/09 ($m)	Plan 2009/10 ($m)	Plan 2010/11 ($m)	Plan 2011/12 ($m)	Plan 2012/13 ($m)	Plan 2013/14 ($m)	Plan 2014/15 ($m)	Plan 2015/16 ($m)	Plan 2016/17 ($m)	Plan 2017/18 ($m)	Total 10 years ($m)
Transmission line maintenance	40.0	40.0	43.9	44.1	48.4	52.5	53.6	57.2	57.2	58.2	495.1
AC substation maintenance	47.8	48.4	55.3	55.7	60.2	66.0	66.2	71.9	72.0	72.2	615.7
DC maintenance	7.4	8.9	8.4	8.4	10.3	9.7	9.7	12.1	10.6	10.6	96.1
IT operations	33.9	37.2	37.8	38.6	39.8	41.1	42.4	43.7	45.1	46.5	406
Investigations	19.0	15.5	16.2	15.4	15.9	16.4	16.9	17.5	18.0	18.6	169.3
Overheads**	80.4	81.9	78.1	85.1	80.6	78.0	83.1	78.6	86.8	92.8	825.5
Total	**228.6**	**231.9**	**239.7**	**247.2**	**255.2**	**263.6**	**271.9**	**280.9**	**289.8**	**298.9**	**2607.8**

*Forecasts beyond 2010/11 are subject to revision as noted in Section 5.

** Overheads in the above table include personnel and contractor costs (both direct and indirect to operating and maintaining the grid), industry levies, accommodation, travel and other minor related expenditure.

Figure 5-1: Forecast operating expenditure*



*Forecasts beyond 2010/11 are subject to revision as noted in Section 5.

5.2 Capital expenditure

Table 5-2: Forecast capital expenditure*

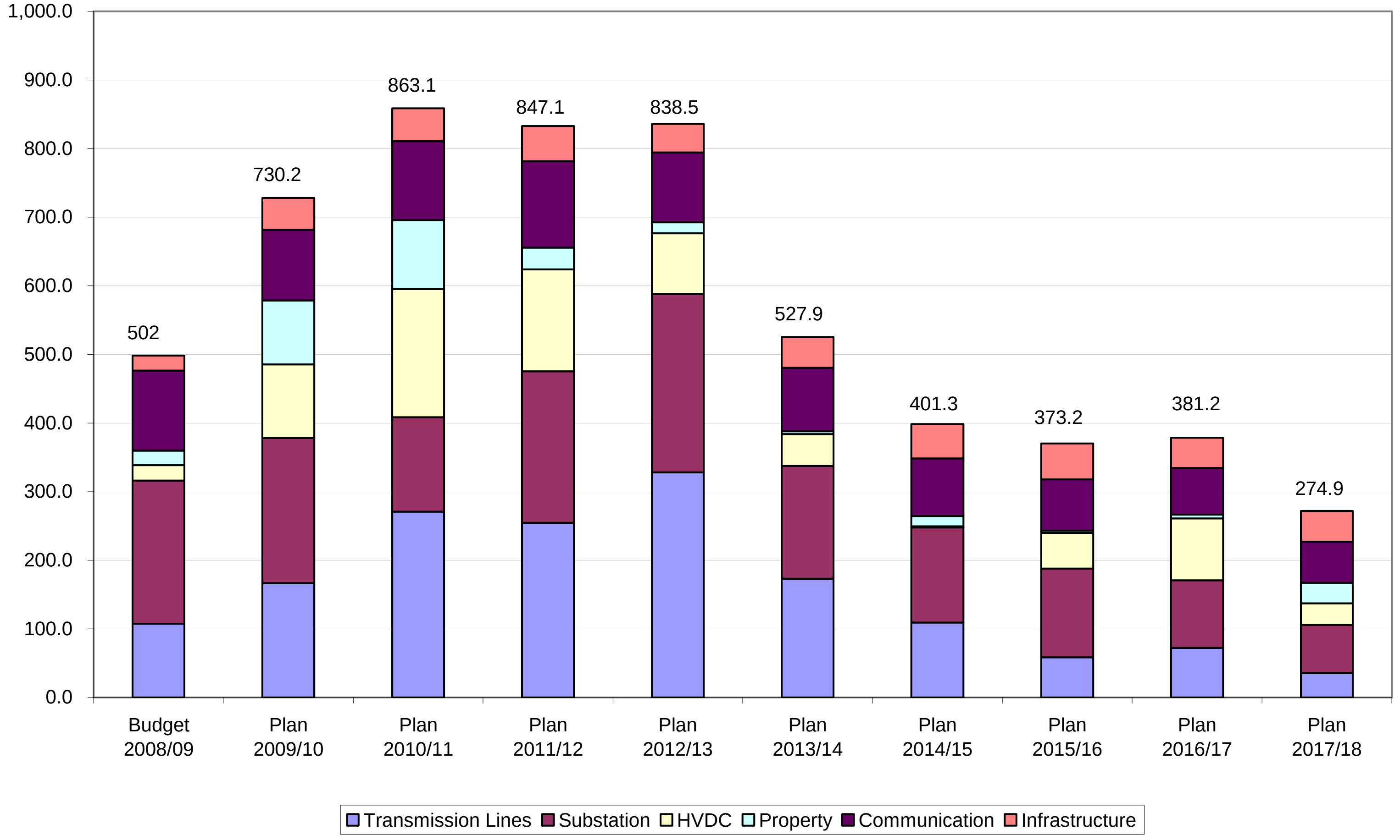
	Budget 2008/09 ($m)	Plan 2009/10 ($m)	Plan 2010/11 ($m)	Plan 2011/12 ($m)	Plan 2012/13 ($m)	Plan 2013/14 ($m)	Plan 2014/15 ($m)	Plan 2015/16 ($m)	Plan 2016/17 ($m)	Plan 2017/18 ($m)	Total 10 years ($m)
Transmission	62.1	82.5	125.3	126.6	243.3	122.6	9.3	0.0	0.0	0.5	772.2
Substation	118.9	135.6	113.2	184.0	217.2	104.6	86.5	88.6	58.2	41.6	1,148.4
HVDC	18.2	105.7	185.0	146.6	82.8	41.3	1.2	52.2	90.1	31.7	754.7
Communication	110.1	91.8	100.8	109.3	86.0	76.9	66.9	59.2	52.0	43.1	796.2
Infrastructure	1.7	0.9	0.1	1.4	1.2	0.0	0.0	0.0	0.0	0.0	5.2
Total Development	**311.1**	**416.4**	**524.4**	**567.9**	**630.5**	**345.4**	**163.9**	**200.0**	**200.3**	**116.9**	**3,476.7**
Transmission	6.1	33.6	88.2	81.2	40.6	7.6	50.5	25.8	24.7	1.4	359.6
Substation	55.9	56.0	4.3	8.6	8.4	17.8	8.9	0.4	0.8	4.7	165.8
HVDC	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4
Communication	2.3	5.0	4.8	2.5	0.5	0.0	0.0	0.0	0.0	0.0	15.0
Infrastructure	0.0	45.3	47.9	50.0	40.3	44.7	50.1	52.5	43.7	45.1	419.7
Total Enhancement	**66.7**	**139.8**	**145.2**	**142.3**	**89.8**	**70.1**	**109.6**	**78.8**	**69.2**	**51.2**	**962.6**
Property	21.3	93.1	100.4	31.7	15.9	4.3	15.0	3.1	5.4	30.0	320.2
Total Property	**21.3**	**93.1**	**100.4**	**31.7**	**15.9**	**4.3**	**15.0**	**3.1**	**5.4**	**30.0**	**320.2**
Transmission	25.9	26.0	32.0	33.3	32.6	31.7	34.0	31.1	32.8	33.2	312.5
Substation	0.1	3.8	2.2	0.8	0.7	0.6	0.8	0.2	0.0	0.0	9.2
HVDC	0.8	1.4	1.1	1.1	5.7	4.7	0.1	0.0	0.0	0.0	14.9
Communication	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Infrastructure	20.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.1
Total Refurbishment	**47.0**	**31.9**	**35.2**	**35.3**	**39.0**	**36.9**	**35.0**	**31.3**	**32.8**	**33.2**	**357.6**
Transmission	13.5	24.9	25.5	13.5	11.7	11.4	15.4	1.6	14.8	0.6	132.9
Substation	33.6	16.0	17.9	27.3	33.6	41.5	42.3	40.2	39.6	23.6	315.8
HVDC	0.9	0.1	0.8	0.6	0.1	0.0	0.2	0.0	0.2	0.0	2.9
Communication	4.2	5.7	9.3	14.1	15.3	15.7	17.2	15.6	16.1	16.6	129.8
Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Replacement	**52.2**	**46.7**	**53.5**	**55.6**	**60.8**	**68.7**	**75.2**	**57.4**	**70.6**	**40.8**	**581.4**

	Budget 2008/09 ($m)	Plan 2009/10 ($m)	Plan 2010/11 ($m)	Plan 2011/12 ($m)	Plan 2012/13 ($m)	Plan 2013/14 ($m)	Plan 2014/15 ($m)	Plan 2015/16 ($m)	Plan 2016/17 ($m)	Plan 2017/18 ($m)	Total 10 years ($m)
Minor fixed assets	3.7	2.2	4.4	14.3	2.5	2.5	2.6	2.8	2.9	2.9	41.0
Total Other	**3.7**	**2.2**	**4.4**	**14.3**	**2.5**	**2.5**	**2.6**	**2.8**	**2.9**	**2.9**	**41.0**
Grand Total	**502.0**	**730.2**	**863.1**	**847.1**	**838.5**	**527.9**	**401.3**	**373.2**	**381.2**	**274.9**	**5,739.5**

*Forecasts beyond 2010/11 are subject to revision as noted in Section 5.

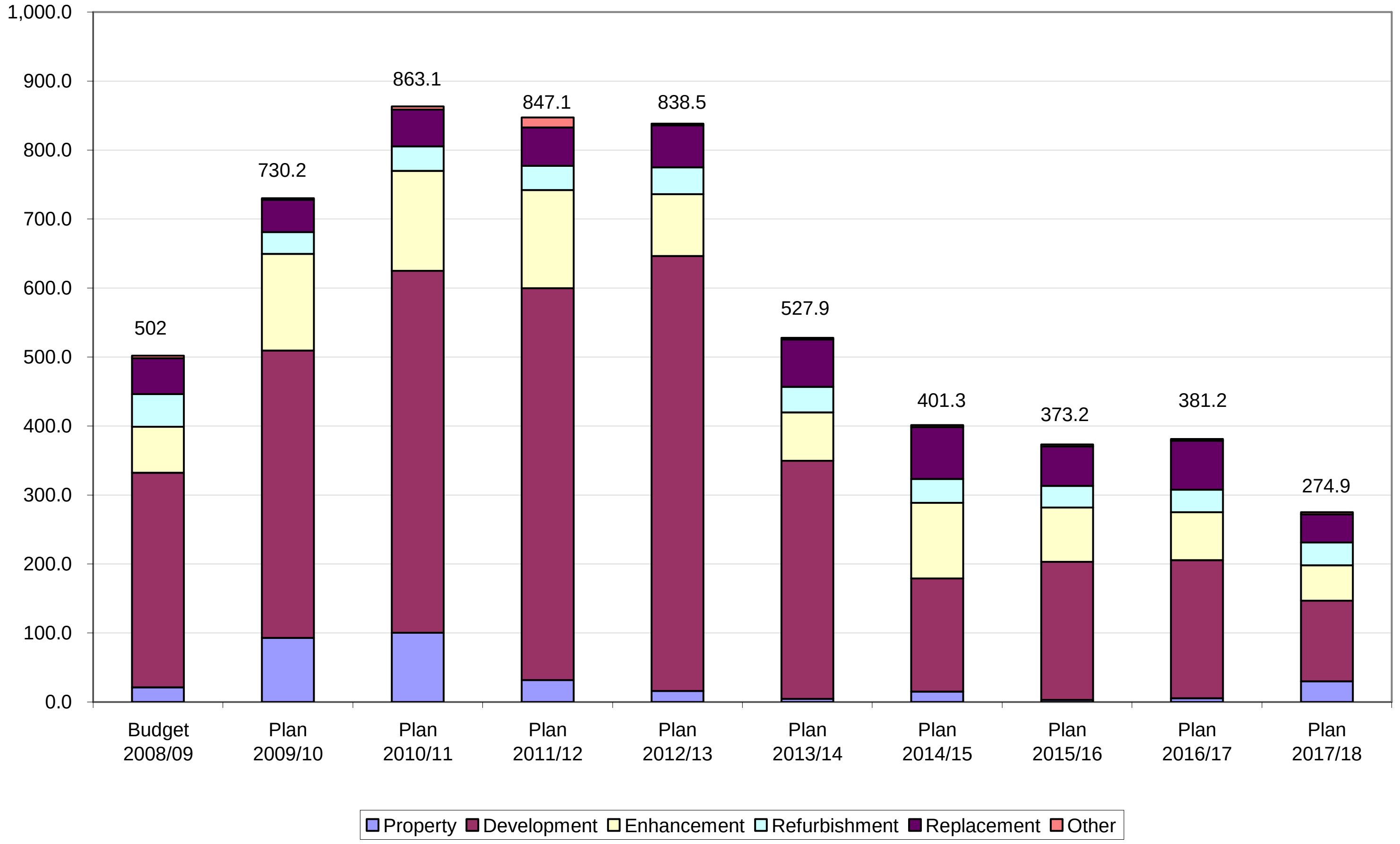
Capital expenditure has been adjusted to exclude the sale of freehold land, system operator expenditure, Energy Market Services expenditure, and includes the capitalisation of new leases.

Figure 5-2: Forecast capital expenditure by asset type*



*Forecasts beyond 2010/11 are subject to revision as noted in Section 5.

Figure 5-3: Forecast capital expenditure by investment category*



*Forecasts beyond 2010/11 are subject to revision as noted in the main body text.